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TS 6.8.4.h.d

April 13, 2022

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Limerick Generating Station, Units 1 and 2
Renewed Facility Operating License Nos. NPF-39 and NPF-85
NRC Docket Nos. 50-352 and 50-353

Subject: Submittal of Changes to Technical Specifications Bases

In accordance with the requirement of Limerick Generating Station (LGS), Units 1 and 2 Technical Specification 6.8.4.h.d, Constellation Energy Generation, LLC, hereby submits a complete updated copy of the Unit 1 and Unit 2 Technical Specifications Bases, which includes changes through the date of this letter.

If you have any questions or require further information, please contact Glenn Stewart at 610-765-5529.

Sincerely,

David P. Helker
Sr. Manager, Licensing
Constellation Energy Generation, LLC

Enclosures: 1) LGS Unit 1 Technical Specifications Bases
2) LGS Unit 2 Technical Specifications Bases

cc: USNRC Region I, Regional Administrator (w/o enclosures)
USNRC Senior Resident Inspector, LGS (w/o enclosures)
USNRC Senior Project Manager, LGS (w/o enclosures)
Director, Bureau of Radiation Protection - Pennsylvania Department
of Environmental Protection (w/o enclosures)

ADD 1
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LIMERICK GENERATING STATION
UNIT 2 TECHNICAL SPECIFICATION PAGE REVISION LIST

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**BASES
FOR
SECTION 2.0
SAFETY LIMITS
AND
LIMITING SAFETY SYSTEM SETTINGS**

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NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Section 2.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

2.1 SAFETY LIMITS

BASES

2.0 INTRODUCTION

The fuel cladding, reactor pressure vessel and primary system piping are the principle barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The Tech Spec Safety Limit is set generically on a fuel product Minimum Critical Power Ratio (MCPR) correlation basis as the MCPR which corresponds to a 95% probability at a 95% confidence level that transition boiling will not occur, referred to as SLMCPR(95/95). The fuel cladding integrity Safety Limit is set such that no significant fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is not less than the limit specified in Specification 2.1.2 MCPR greater than the specified limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding Safety Limit is defined with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. These conditions represent a significant departure from the condition intended by design for planned operation. This is accomplished by having a Safety Limit Minimum Critical Power Ratio (SLMCPR) design basis, referred to as SLMCPR(95/95), which corresponds to a 95% probability at a 95% confidence level (the 95/95 MCPR criterion) that transition boiling will not occur.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

The use of the (GEXL) correlation is not valid for all critical power calculations at pressures below 700 psia for GNF2 [Ref. 2] and 600 psia for GNF3 [Ref. 3] or core flows less than 10% of rated flow. Therefore, the fuel cladding integrity Safety Limit is established by other means. This is done by establishing a limiting condition on core THERMAL POWER with the following basis.

Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be greater than 4.5 psi.

Analyses show that with a bundle flow of 28×10^3 lb/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be greater than 28×10^3 lb/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER of more than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 25% of RATED THERMAL POWER for reactor pressure below 700 psia is conservative.

LIMERICK - UNIT 2

B 2-1 Amendment No. 14, 83, 87, 97, 114,
127, 162, ECR LG 12-00035, 183
Associated with Amendment 199
EC 629259

SAFETY LIMITS

BASES

2.1.2 THERMAL POWER, High Pressure and High Flow

The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Since the parameters which result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions resulting in a departure from nucleate boiling have been used to mark the beginning of the region where fuel damage could occur. Although it is recognized that a departure from nucleate boiling would not necessarily result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. The Technical Specification Safety Limit value is dependent on the fuel product line and the corresponding MCPR correlation, which is cycle independent. The value is based on the Critical Power Ratio (CPR) data statistics and a 95% probability with 95% confidence that rods are not susceptible to boiling transition, referred to as MCPR(95/95).

The Safety Limit is based on GNF2 and/or GNF3 fuel. For cores with a single fuel product line, the SLMCPR(95/95) is the MCPR(95/95) for the fuel type. For cores loaded with a mix of applicable fuel types, the SLMCPR(95/95) is based on the largest (i.e., most limiting) of the MCPR values for the fuel product lines that are fresh or once-burnt at the start of the cycle.

Reference:

1. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).
2. "GEXL17 Correlation for GNF2 Fuel," NEDC-33292P Rev. 3, April 2009
3. "GEXL21 Correlation for GNF3 Fuel," NEDC-33880P Rev. 1, November 2017

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SAFETY LIMITS

BASES

2.1.3 REACTOR COOLANT SYSTEM PRESSURE

The Safety Limit for the reactor coolant system pressure has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to Section III of the ASME Boiler and Pressure Vessel Code 1968 Edition, including Addenda through Summer 1969, which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The Safety Limit of 1325 psig, as measured by the reactor vessel steam dome pressure indicator, is equivalent to 1375 psig at the lowest elevation of the reactor coolant system. The reactor coolant system is designed to the ASME Boiler and Pressure Vessel Code, 1977 Edition, including Addenda through Summer 1977 for the reactor recirculation piping, which permits a maximum pressure transient of 110%, 1375 psig of design pressure, 1250 psig for suction piping and 1500 psig for discharge piping. The pressure Safety Limit is selected to be the lowest transient overpressure allowed by the ASME Boiler and Pressure Vessel Code Section III, Class I.

2.1.4 REACTOR VESSEL WATER LEVEL

With fuel in the reactor vessel during periods when the reactor is shutdown, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level became less than two-thirds of the core height. The Safety Limit has been established at the top of the active irradiated fuel to provide a point which can be monitored and also provide adequate margin for effective action.

2.2 LIMITING SAFETY SYSTEM SETTINGS

BASES

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each parameter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. All four voters will trip (full scram) when any two unbypassed APRM channels exceed their trip setpoints.

APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels.

For operation at low pressure and low flow during STARTUP, the APRM Neutron Flux-Upscale (Setdown) scram setting of 15% of RATED THERMAL POWER provides adequate thermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

LIMITING SAFETY SYSTEM SETTINGS

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The 15% Neutron Flux - Upscale (Setdown) trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Neutron Flux - Upscale setpoint; i.e., for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Simulated Thermal Power - Upscale setpoint, a time constant of 6 ± 0.6 seconds is introduced into the flow-biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow-biased setpoint as shown in Table 2.2.1-1.

A reduced Trip Setpoint and Allowable Value is provided for the Simulated Thermal Power - Upscale Function, applicable when the plant is operating in Single Loop Operation (SLO) per LCO 3.4.1.1. In SLO, the drive flow values (W) used in the Trip Setpoint and Allowable Value equations is reduced by 7.6%. The 7.6% value is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. The Trip Setpoint and Allowable Value thus maintain thermal margins essentially unchanged from those for two-loop operation. The Trip Setpoint and Allowable Value equations for single loop operation are only valid for flows down to $W = 7.6\%$. The Trip Setpoint and Allowable Value do not go below 61.5% and 62.0% RATED THERMAL POWER, respectively. This is acceptable because back flow in the inactive recirculation loop is only an issue with drive flows of approximately 40% or greater (Reference 1).

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unnecessary shutdown.

The APRM channels also include an Oscillation Power Range Monitor (OPRM) Upscale Function. The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR Safety Limit due to anticipated thermal-hydraulic power oscillations. The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into "cells" for evaluation by the OPRM algorithms.

References 2, 3 and 4 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

LIMITING SAFETY SYSTEM SETTINGS

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is $\geq 29.5\%$ and recirculation drive flow is $< 60\%$ as indicated by APRM measured recirculation drive flow. (NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. Refer to TS Bases 3/4.3.1 for further discussion concerning the recirculation drive flow/core flow relationship.) This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. See Reference 5 for additional discussion of OPRM Upscale trip enable region limits. These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Upscale trip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in a cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect oscillatory changes in the neutron flux for one or more cells in that channel.

There are four "sets" of OPRM related setpoints or adjustment parameters: a) OPRM trip auto-enable setpoints for APRM Simulated Thermal Power (29.5%) and recirculation drive flow (60%); b) period based detection algorithm (PBDA) confirmation count and amplitude setpoints; c) period based detection algorithm tuning parameters; and d) growth rate algorithm (GRA) and amplitude based algorithm (ABA) setpoints.

The first set, the OPRM auto-enable region setpoints, are treated as nominal setpoints with no additional margins added as discussed in Reference 5. The settings, 29.5% APRM Simulated Thermal Power and 60% recirculation drive flow, are defined (limit values) in a note to Table 2.2.1-1. The second set, the OPRM PBDA trip setpoints, are established in accordance with methodologies defined in Reference 4, and are documented in the COLR. There are no allowable values for these setpoints. The third set, the OPRM PBDA "tuning" parameters, are established or adjusted in accordance with and controlled by station procedures. The fourth set, the GRA and ABA setpoints, in accordance with References 2 and 3, are established as nominal values only, and controlled by station procedures.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine stop valve and control fast closure trips are bypassed. For a turbine trip or load rejection under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

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LIMITING SAFETY SYSTEM SETTINGS

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint has been used in transient analyses dealing with coolant inventory decrease. The scram setting was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel and pressure limits.

5. Main Steam Line Isolation Valve-Closure

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIVs closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

6. DELETED

7. Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems or a loss of drywell cooling. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant and to the primary containment. The trip setting was selected as low as possible without causing spurious trips.

LIMITING SAFETY SYSTEM SETTING

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

8. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of 25.58 gallons of water.

9. Turbine Stop Valve-Closure

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst design basis transient.

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

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the Reactor Protection System. This trip setting, a faster closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

11. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position is a redundant channel to the automatic protective instrumentation channels and provides additional manual reactor trip capability.

12. Manual Scram

The Manual Scram is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

LIMITING SAFETY SYSTEM SETTING

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

REFERENCES:

1. NEDC-31300, "Single-Loop Operation Analysis for Limerick Generating Station, Unit 1," August 1986.
2. NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.
3. NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.
4. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.
5. BWROG Letter 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), "Guidelines for Stability Option III 'Enable Region' (TAC M92882)," September 17, 1996.

BASES FOR
SECTIONS 3.0 AND 4.0
LIMITING CONDITIONS FOR OPERATION
AND
SURVEILLANCE REQUIREMENTS

AUG 25 1989

NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Sections 3.0 and 4.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

3/4.0 APPLICABILITY

BASES

Specifications 3.0.1 through 3.0.9 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

"Limiting Conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL CONDITIONS or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met. The ACTIONS for not meeting a single LCO adequately manage any increase in plant risk, provided any unusual external conditions (e.g., severe weather, offsite power instability) are considered. In addition, the increased risk associated with simultaneous removal of multiple structures, systems, trains or components from service is assessed and managed in accordance with 10 CFR 50.65(a)(4).

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in an OPERATIONAL CONDITION or other specified condition in which the specification no longer applies.

The specified time limits of the ACTION requirements are applicable from the point of time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered an OPERATIONAL CONDITION in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

3/4.0 APPLICABILITY

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Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval, unless otherwise specified. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown CONDITION when plant operation cannot be maintained within the limits for safe operation defined by the Limiting Conditions for Operation and its ACTION requirements. Planned entry into LCO 3.0.3 should be avoided. If it is not practicable to avoid planned entry into LCO 3.0.3, plant risk should be assessed and managed in accordance with 10 CFR 50.65(a)(4); and the planned entry into LCO 3.0.3 should have less effect on plant safety than other practicable alternatives. One hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This time permits the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to enter lower CONDITIONS of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met, the ACTION is no longer applicable, or time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in COLD SHUTDOWN when a shutdown is required during POWER operation. If the plant is in a lower CONDITION of operation when a shutdown is required, the time limit for entering the next lower CONDITION of operation applies. However, if a lower CONDITION of operation is entered in less time than allowed, the total allowable time to enter COLD SHUTDOWN, or other OPERATIONAL CONDITION, is not reduced. For example, if STARTUP is entered in 2 hours, the time allowed to enter HOT SHUTDOWN is the next 11 hours because the total time to enter HOT SHUTDOWN is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to enter a lower CONDITION of operation in less than the total time allowed.

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The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into an OPERATIONAL CONDITION or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time of ACTION requirements for a higher CONDITION of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower CONDITION of operation.

The shutdown requirements of Specification 3.0.3 do not apply in CONDITIONS 4 and 5, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 establishes limitations on changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability when a Limiting Condition for Operation is not met. It allows placing the unit in an OPERATIONAL CONDITION or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the Limiting Condition for Operation would not be met, in accordance with either Specification 3.0.4.a, Specification 3.0.4.b, or Specification 3.0.4.c.

Specification 3.0.4.a allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met when the associated ACTION requirements to be entered following entry into the OPERATIONAL CONDITION or other specified condition in the Applicability will permit continued operation within the MODE or other specified condition for an unlimited period of time. Compliance with ACTIONS requirements that permit continued operation of the unit for an unlimited period of time in an OPERATIONAL CONDITION or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the OPERATIONAL CONDITION change. Therefore, in such cases, entry into an OPERATIONAL CONDITION or other specified condition in the Applicability may be made and the Required Actions followed after entry into the Applicability.

For example, LCO 3.0.4.a may be used when the Required Action to be entered states that an inoperable instrument channel must be placed in the trip condition within the Completion Time. Transition into a MODE or other specified condition in the Applicability may be made in accordance with LCO 3.0.4 and the channel is subsequently placed in the tripped condition within the Completion Time, which begins when the Applicability is entered. If the instrument channel cannot be placed in the tripped condition and the subsequent default ACTION ("Required Action and associated Completion Time not met") allows the OPERABLE train to be placed in operation, use of LCO 3.0.4.a is acceptable because the subsequent ACTIONS to be entered following entry into the MODE include ACTIONS (place the OPERABLE train in operation) that permit safe plant operation for an unlimited period of time in the MODE or other specified condition to be entered.

Specification 3.0.4.b allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

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The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities be assessed and managed. The risk assessment, for the purposes of Specification 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed OPERATIONAL CONDITION change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the Limiting Condition for Operation would be met prior to the expiration of the ACTION requirement's specified time interval that would require exiting the Applicability.

Specification 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and any corresponding risk management actions. The Specification 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in OPERATIONAL CONDITION 1 for the duration of the specified time interval. Since this is allowable, and since in general the risk impact in that particular OPERATIONAL CONDITION bounds the risk of transitioning into and through the applicable OPERATIONAL CONDITIONS or other specified conditions in the Applicability of the Limiting Condition for Operation, the use of the Specification 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the Specification 3.0.4.b allowance is prohibited. The Limiting Condition for Operations governing these system and components contain Notes prohibiting the use of Specification 3.0.4.b by stating that Specification 3.0.4.b is not applicable.

Specification 3.0.4.c allows entry into a OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met based on a Note in the Specification which states Specification 3.0.4.c is applicable. These specific allowances permit entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability when the associated ACTION requirements to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTION requirements or to a specific ACTION requirement of a Specification. The risk assessments

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performed to justify the use of Specification 3.0.4.b usually only consider systems and components. For this reason, Specification 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Reactor Coolant Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

The provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that result from any unit shutdown. In this

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context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Upon entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met, Specification 3.0.1 and Specification 3.0.2 require entry into the applicable Conditions and ACTION requirements until the Condition is resolved, until the Limiting Condition for Operation is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by Specification 4.0.1. Therefore, utilizing Specification 3.0.4 is not a violation of Specification 4.0.1 or Specification 4.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected Limiting Condition for Operation.

Specification 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to Specifications 3.0.1 and 3.0.2 (e.g., to not comply with the applicable ACTION(s)) to allow the performance of required testing to demonstrate:

- a. The OPERABILITY of the equipment being returned to service, or
- b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance. LCO 3.0.5 should not be used in lieu of other practicable alternatives that comply with Required Actions and that do not require changing the MODE or other specified conditions in the Applicability in order to demonstrate equipment is OPERABLE. LCO 3.0.5 is not intended to be used repeatedly.

An example of demonstrating equipment is OPERABLE with the Required Actions not met is opening a manual valve that was closed to comply with Required Actions to isolate a flowpath with excessive Reactor Coolant System (RCS) Pressure Isolation Valve (PIV) leakage in order to perform testing to demonstrate that RCS PIV leakage is now within limit.

3/4.0 APPLICABILITY

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Examples of demonstrating equipment OPERABILITY include instances in which it is necessary to take an inoperable channel or trip system out of a tripped condition that was directed by a Required Action, if there is no Required Action Note for this purpose. An example of verifying OPERABILITY of equipment removed from service is taking a tripped channel out of the tripped condition to permit the logic to function and indicate the appropriate response during performance of required testing on the inoperable channel.

Examples of demonstrating the OPERABILITY of other equipment are taking an inoperable channel or trip system out of the tripped condition to 1) prevent the trip function from occurring during the performance of required testing on another channel in the other trip system, or 2) to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

The administrative controls in LCO 3.0.5 apply in all cases to systems or components in Chapter 3 of the Technical Specifications, as long as the testing could not be conducted while complying with the Required Actions. This includes the realignment or repositioning of redundant or alternate equipment or trains previously manipulated to comply with ACTIONS, as well as equipment removed from service or declared inoperable to comply with ACTIONS.

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Specification 3.0.6 establishes an exception to Specifications 3.0.1 and 3.0.2 for supported systems that have a support system Limiting Condition for Operation specified in the Technical Specifications (TS). The exception to Specification 3.0.1 is provided because Specification 3.0.1 would require that the ACTIONS of the associated inoperable supported system Limiting Condition for Operation be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support system Limiting Condition for Operation's ACTIONS. These ACTIONS may include entering the supported system's ACTIONS or may specify other ACTIONS. The exception to Specification 3.0.2 is provided because Specification 3.0.2 would consider not entering into the ACTIONS for the supported system within the specified time intervals as a TS noncompliance.

When a support system is inoperable and there is a Limiting Condition for Operation specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' ACTIONS unless directed to do so by the support system's ACTIONS. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' Limiting Condition for Operations' ACTIONS are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's ACTIONS.

However, there are instances where a support system's ACTION may either direct a supported system to be declared inoperable or direct entry into ACTIONS for the supported system. This may occur immediately or after some specified delay to perform some other ACTION. Regardless of whether it is immediate or after some delay, when a support system's ACTION directs a supported system to be declared inoperable or directs entry into ACTIONS for a supported system, the applicable ACTIONS shall be entered in accordance with Specification 3.0.1.

Specification 6.17, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into Specification 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system ACTIONS. The SFDP implements the requirements of Specification 3.0.6.

The following examples use Figure B 3.0-1 to illustrate loss of safety function conditions that may result when a TS support system is inoperable. In this figure, the fifteen systems that comprise Train A are independent and redundant to the fifteen systems that comprise Train B. To correctly use the figure to illustrate the SFDP provisions for a cross train check, the figure establishes a relationship between support and supported systems as follows: the figure shows System 1 as a support system for System 2 and System 3; System 2 as a support system for System 4 and System 5; and System 4 as a support system for System 8 and System 9. Specifically, a loss of safety function may exist when a support system is inoperable and:

- a. A system redundant to system(s) supported by the inoperable support system is also inoperable (EXAMPLE B 3.0.6-1),

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- b. A system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B 3.0.6-2), or
- c. A system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B 3.0.6-3).

For the following examples, refer to Figure B 3.0-1.

EXAMPLE B 3.0.6-1

If System 2 of Train A is inoperable and System 5 of Train B is inoperable, a loss of safety function exists in Systems 5, 10, and 11.

EXAMPLE B 3.0.6-2

If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11.

EXAMPLE B 3.0.6-3

If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10 and 11.

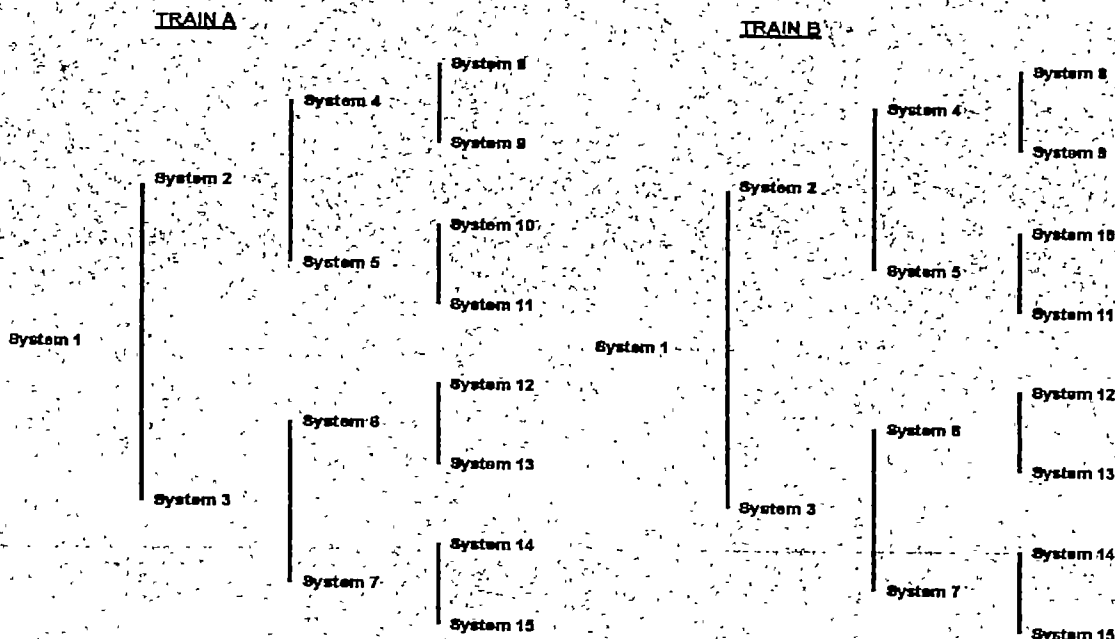


Figure B 3.0-1
Configuration of Trains and Systems

If an evaluation determines that a loss of safety function exists, the appropriate ACTIONS of the Limiting Condition for Operation in which the loss of safety function exists are required to be entered. This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account.

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When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate ACTIONS of the Limiting Condition for Operation in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level), the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the support system. The ACTIONS for a support system Limiting Condition for Operation adequately address the inoperabilities of that system without reliance on entering its supported system Limiting Condition for Operation. When the loss of function is the result of multiple support systems, the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the supported system.

Specification 3.0.7 - Not Used

Specification 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This Specification states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's Limiting Condition for Operation must be declared not met and the associated ACTION requirements shall be met in accordance with Specification 3.0.1.

Specification 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. Specification 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72-hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function and due to the availability of the redundant train of the supported system.

Specification 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. Specification 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12-hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

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The following configuration restrictions shall be applied to the use of Specification 3.0.8:

- (1) Specification 3.0.8.a can only be used if one of the following two means of heat removal is available:
 - a. At least one high pressure makeup path (e.g., using High Pressure Coolant Injection (HPCI) or Reactor Core Isolation Cooling (RCIC) or its equivalent) and heat removal capability (e.g., suppression pool cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s), or
 - b. At least one low pressure makeup path (e.g., Low Pressure Coolant Injection (LPCI) or Core Spray (CS)) and heat removal capability (e.g., suppression pool cooling or shutdown cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s).
- (2) Specification 3.0.8.b can only be used following verification that at least one success path exists, using equipment not associated with the inoperable snubber(s), to provide makeup and core cooling needed to mitigate Loss of Offsite Power (LOOP) accident sequences (i.e., initiated by a seismically-induced LOOP event with concurrent loss of all safety system trains supported by the out-of-service snubbers).

Specification 3.0.8 only applies to the seismic function of snubbers; it does not apply to the non-seismic functions of snubbers. Therefore, each use of Specification 3.0.8 for seismic snubbers that also have non-seismic functions requires confirmation that at least one train (or subsystem) of systems supported by the inoperable snubbers would remain capable of performing their required safety or support functions for postulated design loads other than seismic loads. In addition, a record of the design function of the inoperable snubber (i.e., seismic vs. non-seismic), implementation and compliance with the configuration restrictions defined above, and the associated plant configuration shall be available on a recoverable basis for NRC inspection.

Specification 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (i.e., the Maintenance Rule) does not address seismic risk. However, use of Specification 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

Specification 3.0.9 establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support function(s).

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This Limiting Condition for Operation states that the supported system is not considered to be inoperable

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solely due to required barriers not capable of performing their related support function(s) under the described conditions. Limiting Condition for Operation 3.0.9 allows 30 days before declaring the supported system(s) inoperable and the Limiting Conditions for Operation associated with the supported system(s) not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment.

If the allowed time expires and the barriers are unable to perform their related support function(s), the supported system's Limiting Conditions for Operation must be declared not met and the Conditions and Required Actions entered in accordance with Limiting Condition for Operation 3.0.2.

This provision does not apply to barriers which support ventilation systems or to fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs. This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2, 2001).

The provisions of Limiting Condition for Operation 3.0.9 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories:

- Loss of coolant accidents;
- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado or high wind.

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65 (a)(4), and the associated implementation guidance, Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that barriers are unable to perform their related support function(s).

Limiting Condition for Operation 3.0.9 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one train or subsystem of a multiple train or subsystem supported system, the barriers supporting each of these trains or subsystems must provide their related support function(s) for different categories of initiating events. For example, Limiting Condition for Operation 3.0.9 may be applied for up to 30 days for more than one train of a multiple train supported system if the affected barrier for one train protects against internal flooding and the affected barrier for the other train protects against tornado missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each train.

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The HPCI and RCIC systems are single train systems for injecting makeup water into the reactor during an accident or transient event. For the purposes of Limiting Condition for Operation 3.0.9, the HPCI system, the RCIC system, and the ADS are considered independent subsystems of a single system and Limiting Condition for Operation 3.0.9 can be used on these single train systems in a manner similar to multiple train or subsystem systems.

If during the time that Limiting Condition for Operation 3.0.9 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated Limiting Conditions for Operation declared not met. This 24 hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into Limiting Condition for Operation 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

3/4.0 APPLICABILITY

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Specification 4.0.1 through 4.0.5 establish the general requirements applicable to Surveillance Requirements. SR 4.0.2 and SR 4.0.3 apply in Section 6, Administrative Controls, only when invoked by a Section 6 Specification. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations 10 CFR 50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration, or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

Specification 4.0.1 establishes the requirement that SRs must be met during the OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which the requirements of the Limiting Condition for Operation apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits: Failure to meet a Surveillance within the specified Surveillance time interval and allowed extension, in accordance with Specification 4.0.2, constitutes a failure to meet the Limiting Condition for Operation.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

- a. The systems or components are known to be inoperable, although still meeting the SRs; or
- b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in an OPERATIONAL CONDITION or other specified condition for which the requirements of the associated Limiting Condition for Operation are not applicable, unless otherwise specified. The SRs associated with a Special Test Exception Limiting Condition for Operation are only applicable when the Special Test Exception Limiting Condition for Operation is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given OPERATIONAL CONDITION or other specified condition.

Surveillances, including Surveillances invoked by ACTION requirements, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with Specification 4.0.2, prior to returning equipment to OPERABLE status.

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Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current OPERATIONAL CONDITION or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to an OPERATIONAL CONDITION or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

- a. Control Rod Drive maintenance during refueling that requires scram testing at > 950 psi. However, if other appropriate testing is satisfactorily completed and the scram time testing of Specification 4.1.3.2 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 950 psi to perform other necessary testing.
- b. High pressure coolant injection (HPCI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPCI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

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Specification 4.0.2 establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 24-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend the surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. Likewise, it is not the intent that REFUELING INTERVAL surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been performed within the specified Surveillance time interval and allowed extension. A delay period of up to 24 hours or up to the limit of the specified Surveillance time interval, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with Specification 4.0.2, and not at the time that the specified Surveillance time interval and allowed extension was not met.

When a Section 6.8, "Procedures and Programs," specification states that the provisions of SR 4.0.3 are applicable, it permits the flexibility to defer declaring the testing requirement not met in accordance with SR 4.0.3 when the testing has not been completed within the testing interval (including the allowance of SR 4.0.2 if invoked by the Section 6.8 specification).

This delay period provides adequate time to perform Surveillances that have been missed. This delay period permits the performance of a Surveillance before complying with ACTION requirements or other remedial measures that might preclude performance of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Surveillance time interval based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering OPERATIONAL CONDITION 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to have not been performed when specified, Specification 4.0.3 allows for the full delay period of up to the specified Surveillance time interval to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

Specification 4.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of OPERATIONAL CONDITION changes imposed by ACTION requirements.

3/4.0 APPLICABILITY

BASES

Specification 4.0.3 (Continued)

SR 4.0.3 is only applicable if there is a reasonable expectation the associated equipment is OPERABLE or that variables are within limits, and it is expected that the Surveillance will be met when performed. Many factors should be considered, such as the period of time since the Surveillance was last performed, or whether the Surveillance, or a portion thereof, has ever been performed, and any other indications, tests, or activities that might support the expectation that the Surveillance will be met when performed. An example of the use of SR 4.0.3 would be a relay contact that was not tested as required in accordance with a particular SR, but previous successful performances of the SR included the relay contact; the adjacent, physically connected relay contacts were tested during the SR performance; the subject relay contact has been tested by another SR; or historical operation of the subject relay contact has been successful. It is not sufficient to infer the behavior of the associated equipment from the performance of similar equipment. The rigor of determining whether there is a reasonable expectation a Surveillance will be met when performed should increase based on the length of time since the last performance of the Surveillance. If the Surveillance has been performed recently, a review of the Surveillance history and equipment performance may be sufficient to support a reasonable expectation that the Surveillance will be met when performed. For Surveillances that have not been performed for a long period or that have never been performed, a rigorous evaluation based on objective evidence should provide a high degree of confidence that the equipment is OPERABLE. The evaluation should be documented in sufficient detail to allow a knowledgeable individual to understand the basis for the determination.

Failure to comply with specified Surveillance time intervals and allowed extensions for SRs is expected to be an infrequent occurrence. Use of the delay period established by Specification 4.0.3 is a flexibility which is not intended to be used repeatedly to extend Surveillance intervals.

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While up to 24 hours or the limit of the specified Surveillance time interval is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the Corrective Action Program.

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

Completion of the Surveillance within the delay period allowed by this Specification, or within the allowed times specified in the ACTION requirements, restores compliance with Specification 4.0.1.

Specification 4.0.4 establishes the requirement that all applicable SRs must be met before entry into an OPERATIONAL CONDITION or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

A provision is included to allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability when a Limiting Condition for Operation is not met due to a Surveillance not being met in accordance with Specification 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in Specification 4.0.4 restricting an OPERATIONAL CONDITION change or other specified

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condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per Specification 4.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, Specification 4.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Surveillance time interval does not result in a Specification 4.0.4 restriction to changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability. However, since the Limiting Condition for Operation is not met in this instance, Specification 3.0.4 will govern any restrictions that may (or may not) apply to OPERATIONAL CONDITION or other specified condition changes. Specification 4.0.4 does not restrict changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Surveillance time interval, provided the requirement to declare the Limiting Condition for Operation not met has been delayed in accordance with Specification 4.0.3.

The provisions of Specification 4.0.4 shall not prevent entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 4.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Specification 4.0.5 establishes the requirement that 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 a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda, and the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as required by 10 CFR 50.55a. The provisions of SR 4.0.2 and SR 4.0.3 do not apply to the INSERVICE TESTING PROGRAM unless there is a specific SR referencing usage of the program.

Limerick Generating Station has received a license amendment to implement 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," and may voluntarily comply with the requirements of 10 CFR 50.69 as an alternative to compliance with the following requirements for structures, systems, and components (SSCs) that have a Risk-Informed Safety Class (RISC) of RISC-3:

- (1) The INSERVICE TESTING PROGRAM requirements of 10 CFR 50.55a(f), and
- (2) The inservice inspection, and repair and replacement (with the exception of fracture toughness), requirements for ASME Class 2 and Class 3 SSCs in 10 CFR 50.55a(g).

Therefore, SSCs that have been categorized as RISC-3 in accordance with 10 CFR 50.69 may be removed from the INSERVICE TESTING [IST] PROGRAM and the Inservice Inspection (ISI) Program in accordance with 10 CFR 50.69(b)(1)(v).

RISC-3 SSCs with technical specification surveillance requirements referencing Technical Specification 4.0.5, which have been removed from the IST/ISI programs, are subject to the alternative treatment requirements of 10 CFR 50.69(d)(2). The SSCs must continue to meet the acceptance criteria specified in associated technical specification surveillance requirements, as applicable; however, the surveillance frequency is determined as part of the alternative treatment.

3/4.1 REACTIVITY CONTROL SYSTEMS

BASES

3/4.1.1 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that (1) the reactor can be made subcritical from all operating conditions, (2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and (3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

Since core reactivity values will vary through core life as a function of fuel depletion and poison burnup, the demonstration of SHUTDOWN MARGIN will be performed in the cold, xenon-free condition and shall show the core to be subcritical by at least $R + 0.38\% \Delta k/k$ or $R + 0.28\% \Delta k/k$, as appropriate. The $0.38\% \Delta k/k$ includes uncertainties and calculation biases. The value of R in units of $\% \Delta k/k$ is the difference between the calculated value of minimum shutdown margin during the operating cycle and the calculated shutdown margin at the time of the shutdown margin test at the beginning of cycle. The value of R must be positive or zero and must be determined for each fuel loading cycle.

Two different values are supplied in the Limiting Condition for Operation to provide for the different methods of demonstration of the SHUTDOWN MARGIN. The highest worth rod may be determined analytically or by test. The SHUTDOWN MARGIN is demonstrated by (an insequence) control rod withdrawal at the beginning of life fuel cycle conditions, and, if necessary, at any future time in the cycle if the first demonstration indicates that the required margin could be reduced as a function of exposure. Observation of subcriticality in this condition assures subcriticality with the most reactive control rod fully withdrawn.

This reactivity characteristic has been a basic assumption in the analysis of plant performance and can be best demonstrated at the time of fuel loading, but the margin must also be determined anytime a control rod is incapable of insertion.

3/4.1.2 REACTIVITY ANOMALIES

Since the SHUTDOWN MARGIN requirement for the reactor is small, a careful check on actual conditions to the predicted conditions is necessary, and the changes in reactivity can be inferred from these comparisons of core $k_{\text{effective}}$ (k_{eff}). Since the comparisons are easily done, frequent checks are not an imposition on normal operations. A 1% change is larger than is expected for normal operation so a change of this magnitude should be thoroughly evaluated. A change as large as 1% would not exceed the design conditions of the reactor and is on the safe side of the postulated transients.

REACTIVITY CONTROL SYSTEMS

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3/4.1.3 CONTROL RODS

The specification of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the accident analysis, and (3) the potential effects of the rod drop accident are limited. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

Damage within the control rod drive mechanism could be a generic problem, therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than the fuel cladding safety limit during the limiting power transient analyzed in Section 15.2 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provided the required protection and MCPR remains greater than the fuel cladding safety limit. The occurrence of scram times longer than those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

Scram time testing at zero psig reactor coolant pressure is adequate to ensure that the control rod will perform its intended scram function during startup of the plant until scram time testing at 950 psig reactor coolant pressure is performed prior to exceeding 40% rated core thermal power.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

The OPERABILITY of all SDV vent and drain valves ensures that the SDV vent and drain valves will close during a scram to contain reactor water discharged to the SDV piping. The SDV has one common drain line and one common vent line. Since the vent and drain lines are provided with two valves in series, the single

REACTIVITY CONTROL SYSTEMS

BASES

CONTROL RODS (Continued)

failure of one valve in the open position will not impair the isolation function of the system. Additionally, the valves are required to open on scram reset to ensure that a path is available for the SDV piping to drain freely at other times.

When one SDV vent or drain valve is inoperable in one or more lines, the valves must be restored to OPERABLE status within 7 days. The allowable outage time is reasonable, given the level of redundancy in the lines and the low probability of a scram occurring while the valve(s) are inoperable. The SDV is still isolable since the redundant valve in the affected line is OPERABLE. During these periods, the single failure criterion may not be preserved, and a higher risk exists to allow reactor water out of the primary system during a scram.

If both valves in a line are inoperable, the line must be isolated to contain the reactor coolant during a scram. When a line is isolated, the potential for an inadvertent scram due to high SDV level is increased. ACTION "e" is modified by a note ("****") that allows periodic draining and venting of the SDV when a line is isolated. During these periods, the line may be unisolated under administrative control. This allows any accumulated water in the line to be drained, to preclude a reactor scram on SDV high level. This is acceptable since the administrative controls ensure the valve can be closed quickly, by a dedicated operator, if a scram occurs with the valve open. The 8 hour allowable outage time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and the unlikelihood of significant CRD seal leakage.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. The drive water pressure normal operating range is specified in system operating procedures which provide ranges for system alignment and control rod motion (exercising). Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactor. A control rod is considered trippable if it is capable of fully inserting as a result of a scram signal.

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REACTIVITY CONTROL SYSTEMS

BASES

CONTROL RODS (Continued)

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The required surveillances are adequate to determine that the rods are OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in a peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 10% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RWM to be OPERABLE when THERMAL POWER is less than or equal to 10% of RATED THERMAL POWER provides adequate control.

The RWM provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4.9 of the FSAR and the techniques of the analysis are presented in a topical report, Reference 1, and two supplements, References 2 and 3. Additional pertinent analysis is also contained in Amendment 17 to the Reference 4 Topical Report.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density over the range of power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods. RBM OPERABILITY is required when the limiting condition described in Specification 3.1.4.3 exists.

REACTIVITY CONTROL SYSTEMS

BASES

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

The standby liquid control system provides a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown, assuming that the withdrawn control rods remain fixed in the rated power pattern. To meet this objective it is necessary to inject a quantity of boron which produces a concentration of 660 ppm in the reactor core and other piping systems connected to the reactor vessel. To allow for potential leakage and improper mixing, this concentration is increased by 25%. The required concentration is achieved by having available a minimum quantity of 3,160 gallons of sodium pentaborate solution containing a minimum of 3,754 lbs of sodium pentaborate having the requisite Boron-10 atom % enrichment of 29% as determined from Reference 5. This quantity of solution is a net amount which is above the pump suction shutoff level setpoint thus allowing for the portion which cannot be injected.

The above quantities calculated at 29% Boron-10 enrichment have been demonstrated by analysis to provide a Boron-10 weight equivalent of 185 lbs in the sodium pentaborate solution. Maintaining this Boron-10 weight in the net tank contents ensures a sufficient quantity of boron to bring the reactor to a cold, Xenon-free shutdown.

The pumping rate of 37.0 gpm provides a negative reactivity insertion rate over the permissible solution volume range, which adequately compensates for the positive reactivity effects due to elimination of steam voids, increased water density from hot to cold, reduced doppler effect in uranium, reduced neutron leakage from boiling to cold, decreased control rod worth as the moderator cools, and xenon decay. The temperature requirement ensures that the sodium pentaborate always remains in solution.

With redundant pumps and explosive injection valves and with a highly reliable control rod scram system, operation of the reactor is permitted to continue for short periods of time with the system inoperable or for longer periods of time with one of the redundant components inoperable.

The SLCS system consists of three separate and independent pumps and explosive valves. Two of the separate and independent pumps and explosive valves are required to meet the minimum requirements of this technical specification and, where applicable, satisfy the single failure criterion. To ensure that SLCS pump discharge pressure does not exceed the SLCS relief valve setpoint during operation following an anticipated transient without scram (ATWS) event, no more than two pumps shall be aligned for automatic operation in OPERATIONAL CONDITIONS 1, 2, and 3. This maintains the equivalent control capacity to satisfy 10 CFR 50.62 (Requirements for reduction of risk from anticipated transients without scram (ATWS)). With three pumps aligned for automatic operation, the system is inoperable and ACTION statement (b) applies.

The SLCS must have an equivalent control capacity of 86 gpm of 13% weight sodium pentaborate in order to satisfy 10 CFR 50.62. As part of the ARTS/MELLL program the ATWS analysis was updated to reflect the new rod line. As a result of this it was determined that the Boron 10 enrichment was required to be increased to 29% to prevent exceeding a suppression pool temperature of 190°F. This equivalency requirement is fulfilled by having a system which satisfies the equation given in 4.1.5.b.2.

The upper limit concentration of 13.8% has been established as a reasonable limit to prevent precipitation of sodium pentaborate in the event of a loss of tank heating, which allow the solution to cool. A SLCS Pump flowrate of 37.0 gpm (minimum) and a Sodium Pentaborate Solution concentration of 9% by weight (minimum) will require a Boron-10 enrichment of 49 atom % to be added to the tank. The decreased pump flowrate and increased solution enrichment are acceptable because the results of the ATWS Rule Equation will remain > 1.0.

REACTIVITY CONTROL SYSTEMS

BASES

STANDBY LIQUID CONTROL SYSTEM (Continued)

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume assures that the solution is available for use.

Replacement of the explosive charges in the valves will assure that these valves will not fail because of deterioration of the charges.

The Standby Liquid Control System also has a post-DBA LOCA safety function to buffer Suppression Pool pH in order to maintain bulk pH above 7.0. The buffering of Suppression Pool pH is necessary to prevent iodine re-evolution to satisfy the methodology for Alternative Source Term. Manual initiation is used, and the minimum amount of total boron required for Suppression Pool pH buffering is 256 lbs. Given that at least 185 lbs of Boron-10 is maintained in the tank, the total boron in the tank will be greater than 256 lbs for the range of enrichments from 29% to 62%.

ACTION Statement (a) applies only to OPERATIONAL CONDITIONS 1 and 2 because a single pump can satisfy both the reactor control function and the post-DBA LOCA function to control Suppression Pool pH since boron injection is not required until 13 hours post-LOCA. ACTION Statement (b) applies to OPERATIONAL CONDITIONS 1, 2 and 3 to address the post-LOCA safety function of the SLC system.

1. C. J. Paone, R. C. Stirn and J. A. Woolley, "Rod Drop Accident Analysis for Large BWR's," G. E. Topical Report NEDO-10527, March 1972.
2. C. J. Paone, R. C. Stirn, and R. M. Young, Supplement 1 to NEDO-10527, July 1972.
3. J. M. Haun, C. J. Paone, and R. C. Stirn, Addendum 2, "Exposed Cores," Supplement 2 to NEDO-10527, January 1973.
4. Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel".
5. "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," NEDC-32193P, Revision 2, October 1993.

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3/4.2 POWER DISTRIBUTION LIMITS

BASES

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

This specification assures that the peak cladding temperature (PCT) following the postulated design basis Loss-of-Coolant Accident (LOCA) will not exceed the limits specified in 10 CFR 50.46 and that the fuel design analysis limits specified in NEDE-24011-P-A (Reference 2) will not be exceeded.

Mechanical Design Analysis: NRC approved methods (specified in Reference 2) are used to demonstrate that all fuel rods in a lattice operating at the bounding power history, meet the fuel design limits specified in Reference 2. No single fuel rod follows, or is capable of following, this bounding power history. This bounding power history is used as the basis for the fuel design analysis MAPLHGR limit.

LOCA Analysis: A LOCA analysis is performed in accordance with 10CFR50 Appendix K to demonstrate that the permissible planar power (MAPLHGR) limits comply with the ECCS limits specified in 10 CFR 50.46. The analysis is performed for the most limiting break size, break location, and single failure combination for the plant, using the evaluation model described in Reference 9.

The MAPLHGR limit as shown in the CORE OPERATING LIMITS REPORT is the most limiting composite of the fuel mechanical design analysis MAPLHGR and the ECCS MAPLHGR limit.

Only the most limiting MAPLHGR values are shown in the CORE OPERATING LIMITS REPORT for multiple lattice fuel. Compliance with the specific lattice MAPLHGR operating limits, which are available in Reference 3, is ensured by use of the process computer.

As a result of no longer utilizing an APRM trip setdown requirement, additional constraints are placed on the MAPLHGR limits to assure adherence to the fuel-mechanical design bases. These constraints are introduced through the MAPFAC(P) and MAPFAC(F) factors as defined in the COLR.

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POWER DISTRIBUTION LIMITS

BASES

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POWER DISTRIBUTION LIMITS

BASES

3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady-state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity MCPR(99.9%), and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady-state operating limit, it is required that less than 0.1% of fuel rods in the core are susceptible to transition boiling of that the resulting MCPR does not decrease below the operating limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0-2 that are input to a BWR system dynamic behavior transient computer program. The codes used to evaluate transients are discussed in Reference 2.

MCPR(99.9%) is determined to ensure more than 99.9% of the fuel rods in the core are not susceptible to boiling transition using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved Critical Power correlations. Details of the MCPR(99.9%) calculation are given in Reference 2. Reference 2 also includes a tabulation of the uncertainties and the nominal values of the parameters used in the MCPR99.9% statistical analysis.

The MCPR operating limits are derived from the MCPR(99.9%) value and the transient analysis, and are dependent on the operating core flow and power state (MCPR(F), and MCPR(P), respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Ref. 6). Flow dependent MCPR limits (MCPR(F)) are determined by steady state thermal hydraulic methods with key physics response inputs benchmarked using the three dimensional BWR simulator code (Ref. 7) to analyze slow flow runout transients.

Power dependent MCPR limits (MCPR(P)) are determined by approved transient analysis (Reference 2). Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scrams are bypassed, high and low flow MCPR(P), operating limits are provided for operating between 25% RTP and 30% RTP.

The MCPR operating limits specified in the COLR (MCPR(99.9%) value MCPR(F), and MCPR(P) values are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the MCPR(F), and MCPR(P) limits which are based on the MCPR(99.9%) limit specified in the COLR.

POWER DISTRIBUTION LIMITS

BASES

MINIMUM CRITICAL POWER RATIO (Continued)

At THERMAL POWER levels less than or equal to 25% of RATED THERMAL POWER, the reactor will be operating at minimum recirculation pump speed and the moderator void content will be very small. For all designated control rod patterns which may be employed at this point, operating plant experience indicates that the resulting MCPR value is in excess of requirements by a considerable margin. During initial startup testing of the plant, a MCPR evaluation will be made at 25% of RATED THERMAL POWER level with minimum recirculation pump speed. The MCPR margin will thus be demonstrated such that future MCPR evaluation below this power level will be shown to be unnecessary. The daily requirement for calculating MCPR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR when a limiting control rod pattern is approached ensures that MCPR will be known following a change in THERMAL POWER or power shape, regardless of magnitude, that could place operation at a thermal limit.

3/4.2.4 LINEAR HEAT GENERATION RATE

This specification assures that the Linear Heat Generation Rate (LHGR) in any rod is less than the design linear heat generation even if fuel pellet densification is postulated.

Reference:

1. Deleted.
2. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).
3. "Basis of MAPLHGR Technical Specifications for Limerick Unit 2," NEDC-31930P (as amended).
4. Deleted
5. Increased Core Flow and Partial Feedwater Heating Analysis for Limerick Generating Station Unit 2 Cycle 1, NEDC-31578P, March 1989 including Errata and Addenda Sheet No. 1 dated May 31, 1989.
6. NEDC-32193P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," Revision 2, October 1993.
7. NEDO-30130-A, "Steady State Nuclear Methods," May 1985.
8. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," October 1978.
9. NEDC-32170P, "Limerick Generating Station Units 1 and 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," June 1993.

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3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

- a. Preserve the integrity of the fuel cladding.
- b. Preserve the integrity of the reactor coolant system.
- c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and
- d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed.

The system meets the intent of IEEE-279 for nuclear power plant protection systems. Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System" and NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function." The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

The APRM Functions include five Functions accomplished by the four APRM channels (Functions 2.a, 2.b, 2.c, 2.d, and 2.f) and one accomplished by the four 2-Out-Of-4 Voter channels (Function 2.e). Two of the five Functions accomplished by the APRM channels are based on neutron flux only (Functions 2.a and 2.c), one Function is based on neutron flux and recirculation drive flow (Function 2.b) and one is based on equipment status (Function 2.d). The fifth Function accomplished by the APRM channels is the Oscillation Power Range Monitor (OPRM) Upscale trip Function 2.f, which is based on detecting oscillatory characteristics in the neutron flux. The OPRM Upscale Function is also dependent on average neutron flux (Simulated Thermal Power) and recirculation drive flow, which are used to automatically enable the output trip.

The Two-Out-Of-Four Logic Module includes 2-Out-Of-4 Voter hardware and the APRM Interface hardware. The 2-Out-Of-4 Voter Function 2.e votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. This voting is accomplished by the 2-Out-Of-4 Voter hardware in the Two-Out-Of-Four Logic Module. The voter includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The analysis in Reference 2 took credit for this redundancy in the justification of the 12-hour allowed out-of-service time for

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

Action b, so the voter Function 2.e must be declared inoperable if any of its functionality is inoperable. The voter Function 2.e does not need to be declared inoperable due to any failure affecting only the APRM Interface hardware portion of the Two-Out-Of-Four Logic Module.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. To provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. In addition, no more than 9 LPRMs may be bypassed between APRM calibrations (weekly gain adjustments). For the OPRM Upscale Function 2.f, LPRMs are assigned to "cells" of 3 or 4 detectors. A minimum of 23 cells (Reference 9), each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for each APRM channel for the OPRM Upscale Function 2.f to be OPERABLE in that channel. LPRM gain settings are determined from the local flux profiles measured by the TIP system. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 2000 EFPH frequency is based on operating experience with LPRM sensitivity changes.

References 4, 5 and 6 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in any cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux for one or more cells in that channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is at $\geq 25\%$ RATED THERMAL POWER. The 25% RATED THERMAL POWER level is selected to provide margin in the unlikely event that a reactor power increase transient occurring while the plant is operating below 29.5% RATED THERMAL POWER causes a power increase to or beyond the 29.5% RATED THERMAL POWER OPRM Upscale trip auto-enable point without operator action. This OPERABILITY requirement assures that the OPRM Upscale trip automatic-enable function will be OPERABLE when required.

Actions a, b and c define the Action(s) required when RPS channels are discovered to be inoperable. For those Actions, separate entry condition is allowed for each inoperable RPS channel. Separate entry means that the allowable time clock(s) for Actions a, b or c start upon discovery of inoperability for that specific channel. Restoration of an inoperable RPS channel satisfies only the action statements for that particular channel. Action statement(s) for remaining inoperable channel(s) must be met according to their original entry time.

A Note has been provided to modify the Actions when Functional Unit 2.b and 2.c channels are inoperable due to failure of SR 4.3.1.1 and gain adjustments are necessary. The Note allows entry into associated Actions to be delayed for up to 2 hours if the APRM is indicating a lower power value than the calculated power (i.e., the gain adjustment factor (GAF) is high (non-conservative)). The GAF for any channel is defined as the power value determined by the heat balance divided by the APRM reading for that channel. Upon completion of the gain adjustment, or

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

expiration of the allowed time, the channel must be returned to OPERABLE status or the applicable Actions taken. This Note is based on the time required to perform gain adjustments on multiple channels.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (NEDC-30851P-A and NEDC-32410P-A) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided that the associated Function's (identified as a "Functional Unit" in Table 3.3.1-1) inoperable channel is in one trip system and the Function still maintains RPS trip capability. Alternatively, an allowable out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

The requirements of Action a are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic, including the IRM Functions and APRM Function 2.e (trip capability associated with APRM Functions 2.a, 2.b, 2.c, 2.d, and 2.f are discussed below), this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip).

For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 9 (Turbine Stop Valve-Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The completion time to satisfy the requirements of Action a is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels. Alternatively, the completion time can be determined in accordance with the Risk Informed Completion Time Program.

With trip capability maintained, i.e., Action a satisfied, Actions b and c as applicable must still be satisfied. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Action b requires that the channel or the associated trip system must be placed in the tripped condition. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue.

As noted, placing the trip system in trip is not applicable to satisfy Action b for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, the Action b requirements can only be satisfied by placing the inoperable APRM channel in trip. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and the requirement to satisfy Action a.

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action c must be satisfied when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, normally the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system (see additional bases discussion above related to loss of trip capability and the requirements of Action a, and special cases for Functions 2.a, 2.b, 2.c, 2.d, 2.f, 5 and 9).

The requirements of Action c limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in NEDC-30851P-A for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function must have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing the actions required by Action c restores RPS to a reliability level equivalent to that evaluated in NEDC-30851P-A, which justified a 12 hour allowable out of service time as allowed by Action b. To satisfy the requirements of Action c, the trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what OPERATIONAL CONDITION the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

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

As noted, Action c is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-Out-Of-4 voter and other non-APRM channels for which Action c applies. For an inoperable APRM channel, the requirements of Action b can only be satisfied by tripping the inoperable APRM channel. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure.

If it is not desired to place the channel (or trip system) in trip to satisfy the requirements of Action a, Action b or Action c (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Action d requires that the Action defined by Table 3.3.1-1 for the applicable Function be initiated immediately upon expiration of the allowable out of service time.

Table 3.3.1-1, Function 2.f, references Action 10, which defines the action required if OPRM Upscale trip capability is not maintained. Action 10b is required to address identified equipment failures. Action 10a is to address common mode vendor/industry identified issues that render all four OPRM channels inoperable at once. For this condition, References 2 and 3 justified use of alternate methods to detect and suppress oscillations for a limited period of

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

time, up to 120 days. The alternate methods are procedurally established consistent with the guidelines identified in Reference 7 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed completion time to implement the alternate methods is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place. The 120-day period during which use of alternate methods is allowed is intended to be an outside limit to allow for the case where design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. The evaluation of the use of alternate methods concluded, based on engineering judgment, that the likelihood of an instability event that could not be adequately handled by the alternate methods during the 120-day period was negligibly small. Plant startup may continue while operating within the allowed completion time of Action 10a. The primary purpose of this is to allow an orderly completion, without undue impact on plant operation, of design and verification activities in the event of a required design change to the OPRM Upscale function. This exception is not intended as an alternative to restoring inoperable equipment to OPERABLE status in a timely manner.

Action 10a is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to be accomplished within the completion times allowed for LCO 3.3.1 Action a or Action b, as applicable. Action 10b applies when routine equipment OPERABILITY cannot be restored within the allowed completion times of LCO 3.3.1 Actions a or b, or if a common mode OPRM deficiency cannot be corrected and OPERABILITY of the OPRM Upscale Function restored within the 120-day allowed completion time of Action 10a.

The OPRM Upscale trip output shall be automatically enabled (not-bypassed) when APRM Simulated Thermal Power is $\geq 29.5\%$ and recirculation drive flow is $< 60\%$ as indicated by APRM measured recirculation drive flow. NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. As noted in Table 4.3.1.1-1, Note c, CHANNEL CALIBRATION for the OPRM Upscale trip Function 2.f includes confirming that the auto-enable (not-bypassed) setpoints are correct. Other surveillances ensure that the APRM Simulated Thermal Power properly correlates with THERMAL POWER (Table 4.3.1.1-1, Note d) and that recirculation drive flow properly correlates with core flow (Table 4.3.1.1-1, Note g).

If any OPRM Upscale trip auto-enable setpoint is exceeded and the OPRM Upscale trip is not enabled, i.e., the OPRM Upscale trip is bypassed when APRM Simulated Thermal Power is $\geq 29.5\%$ and recirculation drive flow is $< 60\%$, then the affected channel is considered inoperable for the OPRM Upscale Function. Alternatively, the OPRM Upscale trip auto-enable setpoint(s) may be adjusted to place the channel in the enabled condition (not-bypassed). If the OPRM Upscale trip is placed in the enabled condition, the surveillance requirement is met and the channel is considered OPERABLE.

3/4.3 INSTRUMENTATION

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3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 4.3.1.1-1, Note g, CHANNEL CALIBRATION for the APRM Simulated Thermal Power - Upscale Function 2.b and the OPRM Upscale Function 2.f, includes the recirculation drive flow input function. The APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function both require a valid drive flow signal. The APRM Simulated Thermal Power - Upscale Function uses drive flow to vary the trip setpoint. The OPRM Upscale Function uses drive flow to automatically enable or bypass the OPRM Upscale trip output to RPS. A CHANNEL CALIBRATION of the APRM recirculation drive flow input function requires both calibrating the drive flow transmitters and establishing a valid drive flow / core flow relationship. The drive flow / core flow relationship is established once per refuel cycle, while operating within 10% of rated core flow and within 10% of RATED THERMAL POWER. Plant operational experience has shown that this flow correlation methodology is consistent with the guidance and intent in Reference 8. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function.

For the Simulated Thermal Power - Upscale Function (Function 2.b), the CHANNEL CALIBRATION surveillance requirement is modified by two Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the Trip Setpoint. The as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the Trip Setpoint, then the channel shall be declared inoperable. The as-left tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy and the measurement and test equipment error (including readability). The as-found tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy, instrument drift, and the measurement and test equipment error (including readability).

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to the reactor power calculated from a heat balance if the heat balance calculated reactor power exceeds the APRM channel output by more than 2% RTP.

This Surveillance does not preclude making APRM channel adjustments, if desired, when the heat balance calculated reactor power is less than the APRM channel output. To provide close agreement between the APRM indicated power and to preserve operating margin, the APRM channels are normally adjusted to within +/- 2% of the heat balance calculated reactor power. However, this agreement is not required for OPERABILITY when APRM output indicates a higher reactor power than the heat balance calculated reactor power.

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 3.3.1-2, Note "*", the redundant outputs from the 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8 to determine the interval between tests for application of Specification 4.3.1.3 (REACTOR PROTECTION SYSTEM RESPONSE TIME). The note further requires that testing of OPRM and APRM outputs shall be alternated.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-Out-Of-4 Voter channel for that function, and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. This testing frequency is twice the frequency justified by References 2 and 3.

Automatic reactor trip upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable except for the APRM Simulated Thermal Power - Upscale and Neutron Flux - Upscale trip functions and the OPRM Upscale trip function (Table 3.3.1-2, Items 2.b, 2.c, and 2.f). Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) in-place, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. Response time testing for the sensors as noted in Table 3.3.1-2 is not required based on the analysis in NEDO-32291-A. Response time testing for the remaining channel components is required as noted. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

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3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 2, "Technical Specification Improvement Analysis for BWR Instrumentation Common to RPS and ECCS Instrumentation" as approved by the NRC and documented in the NRC Safety Evaluation Report (SER) (letter to D.N. Grace from C.E. Rossi dated January 6, 1989) and NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the NRC SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Automatic closure of the MSIVs upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

Response time testing for sensors are not required based on the analysis in NEDO-32291-A. Response time testing of the remaining channel components is required as noted in Table 3.3.2-3.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. Primary containment isolation valves that are actuated by the isolation signals specified in Technical Specification Table 3.3.2-1 are identified in Technical Requirements Manual Table 3.6.3-1.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.3.2 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

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3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.3.A REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation

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3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

if they will be isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, "Reactor Pressure Vessel (RPV) Water Inventory Control (WIC)," and the definition of DRAIN TIME. There are functions that support automatic isolation of Residual Heat Removal (RHR) subsystem and Reactor Water Cleanup (RWCU) system penetration flow path(s) on low RPV water level.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered postulated in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure. It is assumed, based on engineering judgment, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Permissive and interlock setpoints are generally considered as nominal values without regard to measurement accuracy.

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

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3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

RHR System Isolation - Reactor Vessel Water Level Low - Level 3

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level Low - Level 3 Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

Reactor Vessel Water Level Low - Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level Low - Level 3 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level Low - Level 3 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level Low - Level 3 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level Low - Level 3 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 2 valves.

Reactor Water Cleanup (RWCU) System Isolation - Reactor Vessel Water Level - Low, Low - Level 2

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level - Low, Low - Level 2 Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System.

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3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

Reactor Vessel Water Level - Low, Low - Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level - Low, Low - Level 2 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level - Low, Low - Level 2 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level - Low, Low Level 2 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level - Low, Low - Level 2 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 3 valves.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Actions

A note has been provided to modify the ACTIONS related to RPV Water Inventory Control instrumentation channels. The ACTIONS for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for each inoperable RPV Water Inventory Control instrumentation channel.

ACTION a. directs taking the appropriate ACTION referenced in Table 3.3.3.A-1. The applicable ACTION referenced in the table is Function dependent.

RHR System Shutdown Cooling Mode Isolation, Reactor Vessel Water Level Low - Level 3, and Reactor Water Cleanup System Isolation, Reactor Vessel Water Level - Low, Low - Level 2 functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. If the instrumentation is inoperable, ACTION 38 directs immediate action to place the channel in trip. With the inoperable channel in the tripped condition, the remaining channel will isolate the penetration flow path on low water level. If both channels are inoperable and placed in trip, the penetration flow path will be isolated. Alternatively, ACTION 38 requires the associated penetration flow path(s) are incapable of automatic isolation and calculation of DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

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3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81 "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.
2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.
3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.
4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.
5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

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3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 175 ms. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression, and the response time of the system logic.

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Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage time have been determined in accordance with NEDC-30851P, Supplement I, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

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INSTRUMENTATION

BASES

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that: (1) the radiation levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded, and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63, and 64.

The surveillance interval for the Main Control Room Normal Fresh Air Supply Radiation Monitor is determined in accordance with the Surveillance Frequency Control Program.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

3/4.3.7.2 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.7.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.4 REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

The OPERABILITY of the remote shutdown system instrumentation and controls ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criterion 19 of 10 CFR Part 50, Appendix A. The Unit 1 RHR transfer switches are included only due to their potential impact on the RHRSW system, which is common to both units.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 2, requires two OPERABLE channels of Reactor Vessel Water Level monitoring from each of two overlapping instrumentation loops to ensure monitoring of Reactor Vessel Water Level over the range of -350 inches to +60 inches. Each channel is comprised of one OPERABLE Wide Range Level instrument loop (-150 inches to +60 inches) and one OPERABLE Fuel Zone Range instrument loop (-350 inches to -100 inches). Both instrument loops, Wide Range and Fuel Zone Range, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (Wide Range and Fuel Zone Range) is not maintained.

INSTRUMENTATION

BASES

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION (continued)

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 13, requires two OPERABLE channels of Neutron Flux monitoring from each of three overlapping instrumentation loops to ensure monitoring of Neutron Flux over the range of $10^{-6}\%$ to 100% full power. Each channel is comprised of one OPERABLE SRM ($10^{-9}\%$ to $10^{-3}\%$ power), one OPERABLE IRM ($10^{-4}\%$ to 40% power) and one OPERABLE APRM (0% to 125% power). All three instrument loops, SRM, IRM and APRM, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (SRM, IRM, and APRM) is not maintained.

3/4.3.7.6 SOURCE RANGE MONITORS

The source range monitors provide the operator with information of the status of the neutron level in the core at very low power levels during startup and shutdown. At these power levels, reactivity additions shall not be made without this flux level information available to the operator. When the intermediate range monitors are on scale, adequate information is available without the SRMs and they can be retracted.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

INSTRUMENTATION

BASES

3/4.3.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.8 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.9 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

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INSTRUMENTATION

BASES

3/4.3.7.10 (Deleted)

3/4.3.7.11 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.12 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM AND THE TRM.

3/4.3.8 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

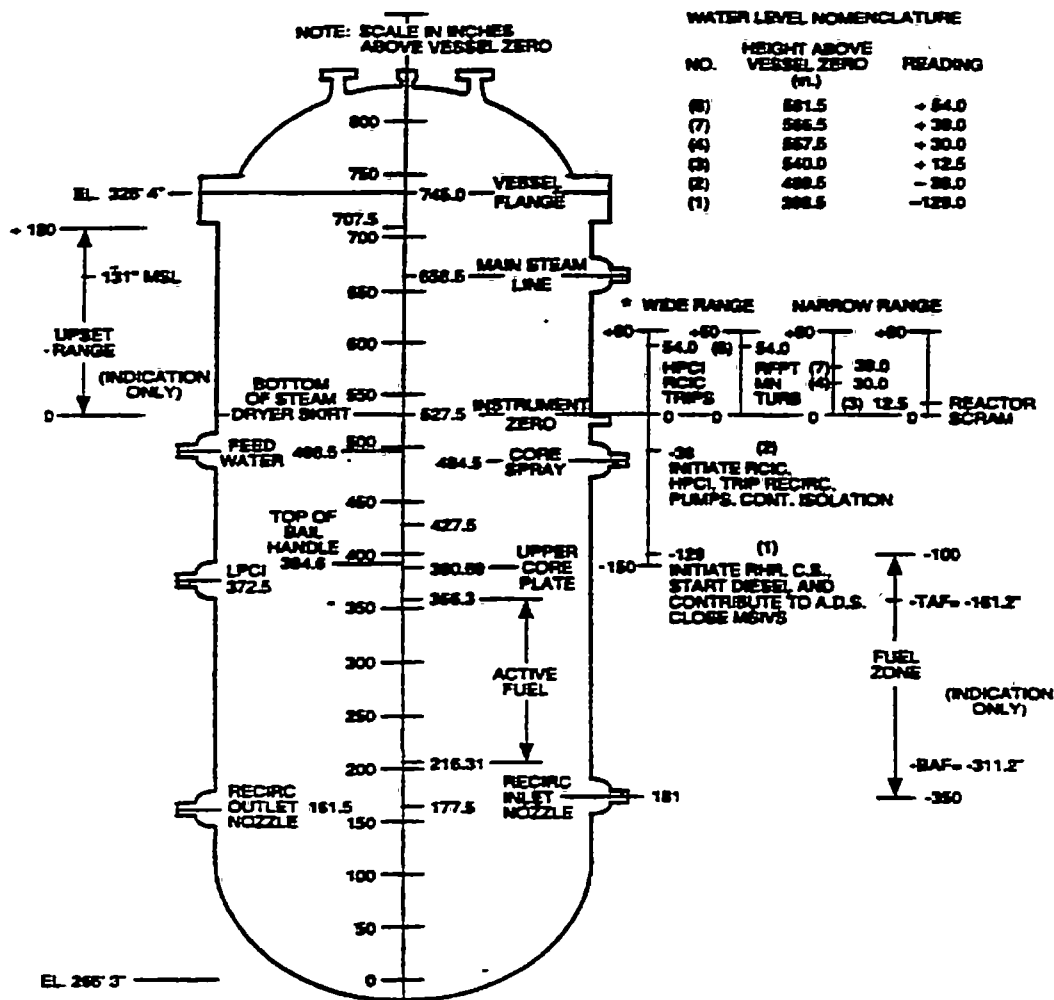
3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

The feedwater/main turbine trip system actuation instrumentation is provided to initiate action of the feedwater system/main turbine trip system in the event of failure of feedwater controller under maximum demand.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

REFERENCES:

1. NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.
2. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," October 1995.
3. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," November 1997.
4. NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.
5. NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.
6. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.
7. Letter, L. A. England (BWROG) to M. J. Virgilio, "BWR Owners' Group Guidelines for Stability Interim Corrective Action," June 6, 1994.
8. GE Service Information Letter No. 516, "Core Flow Measurement - GE BWR/3, 4, 5 and 6 Plants," July 26, 1990.
9. GE Letter NSA 00-433, Alan Chung (GE) to Sujit Chakraborty (GE), "Minimum Number of Operable OPRM Cells for Option III Stability at Limerick 1 & 2," May 02, 2001.

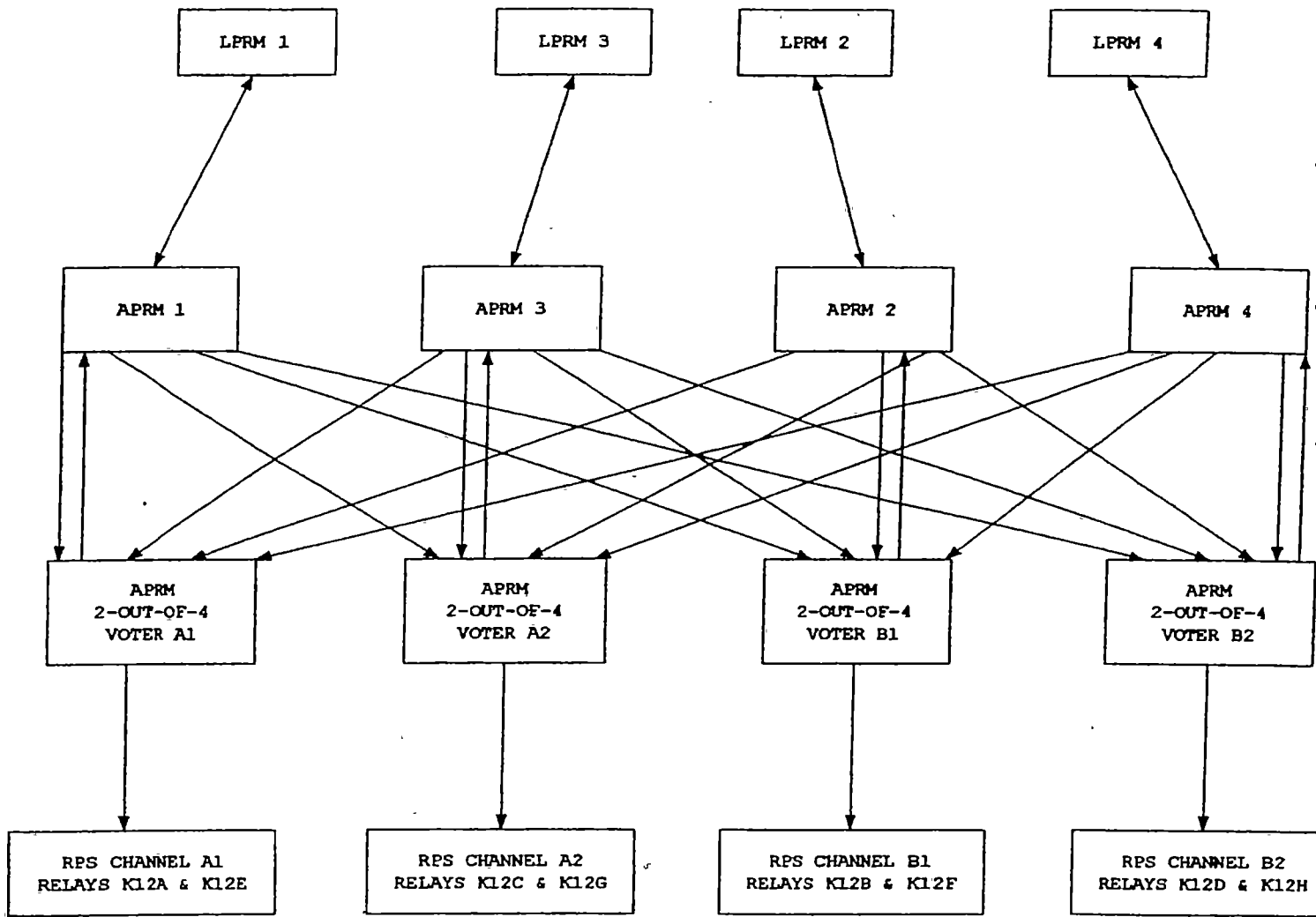


* Wide Range Level

This indication is reactor coolant temperature sensitive. The calibration is thus made at rated conditions. The level error at low pressures (temperatures) is bounded by the safety analysis which reflects the weight-of-coolant above the lower tap, and not indicated level.

BASES FIGURE B 3/4.3-1

REACTOR VESSEL WATER LEVEL



BASES FIGURE B 3/4.3-2

APRM CONFIGURATION

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3/4.4 REACTOR COOLANT SYSTEM

BASES

3/4.4.1 RECIRCULATION SYSTEM

The impact of single recirculation loop operation upon plant safety is assessed and shows that single-loop operation is permitted if the MCP(R99.9%) is increased as noted in the COLR, APRM scram and control rod block setpoints are adjusted as noted in Tables 2.2.1-1 and 3.3.6-2, respectively.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis-accident, increase the blowdown area and reduce the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

Additionally, surveillance on the pump speed of the operating recirculation loop is imposed to exclude the possibility of excessive internal vibration. The surveillance on differential temperatures below 30% RATED THERMAL POWER or 50% rated recirculation loop flow is to mitigate the undue thermal stress on vessel nozzles, recirculation pump and vessel bottom head during the extended operation of the single recirculation loop mode.

Surveillance of recirculation loop flow, total core flow, and diffuser-to-lower plenum differential pressure is designed to detect significant degradation in jet pump performance that precedes jet pump failure. This surveillance is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns," engineering judgment of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (pump flow and loop flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

REACTOR COOLANT SYSTEM

BASES

3/4.4.1 RECIRCULATION SYSTEM (continued)

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system. Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data.

Recirculation pump speed mismatch limits are in compliance with the ECCS LOCA analysis design criteria for two recirculation loop operation. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA. In the case where the mismatch limits cannot be maintained during two loop operation, continued operation is permitted in a single recirculation loop mode.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Sudden equalization of a temperature difference > 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1325 psig in accordance with the ASME Code. A total of 12 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case upset transient.

Demonstration of the safety/relief valve lift settings will occur only during shutdown. The safety/relief valves will be removed and either set pressure tested or replaced with spares which have been previously set pressure tested and stored in accordance with manufacturers recommendations at the frequency specified in the Surveillance Frequency Control Program.

REACTOR COOLANT SYSTEM

BASES

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

BACKGROUND

UFSAR Safety Design Basis (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of Reactor Coolant System (RCS) PRESSURE BOUNDARY LEAKAGE. Regulatory Guide 1.45, Revision 0, (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on leakage from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms.

Systems for quantifying the leakage are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action. Leakage from the RCPB inside the drywell is detected by at least one of four (4) independently monitored variables which include drywell sump flow monitoring equipment with the required RCS leakage detection instrumentation (i.e., the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump), drywell gaseous radioactivity, drywell unit cooler condensate flow rate and drywell pressure/temperature levels. The primary means of quantifying leakage in the drywell is the drywell sump monitoring system for UNIDENTIFIED LEAKAGE and the drywell equipment drain tank flow monitoring system for IDENTIFIED LEAKAGE. IDENTIFIED leakage is not germane to this Tech Spec and the associated drywell equipment drain tank flow monitoring system is not included.

The drywell floor drain sump flow monitoring system monitors UNIDENTIFIED LEAKAGE collected in the floor drain sump. UNIDENTIFIED LEAKAGE consists of leakage from RCPB components inside the drywell which are not normally subject to leakage and otherwise routed to the drywell equipment drain sump. The primary containment floor drain sump has transmitters that supply level indication to the main control room via the plant monitoring system. The floor drain sump level transmitters are associated with High/Low level switches that open/close the sump tank drain valves automatically. The level instrument processing unit calculates an average leak rate (gpm) for a given measurement period which resets whenever the sump drain valve closes. The level processing unit provides an alarm to the main control room each time the average leak rate changes by a predetermined value since the last time the alarm was reset. For the drywell floor drain sump flow monitoring system, the setpoint basis is a 1 gpm change in UNIDENTIFIED LEAKAGE.

An alternate to the drywell floor drain sump flow monitoring system for quantifying UNIDENTIFIED LEAKAGE is the drywell equipment drain sump monitoring system, if the drywell floor drain sump is overflowing to the drywell equipment drain sump. In this configuration, the drywell equipment drain sump collects all leakage into the drywell equipment drain sump and the overflow from the drywell floor drain sump. Therefore, if the drywell floor drain sump is overflowing to the drywell equipment drain sump, the drywell equipment drain sump monitoring system can be used to quantify UNIDENTIFIED LEAKAGE. In this condition, all leakage measured by the drywell equipment drain sump monitoring system is assumed to be UNIDENTIFIED LEAKAGE. The leakage determination process, including the transition to and use of the alternate method is described in station procedures. The alternate method would only be used when the drywell floor drain sump flow monitoring system is unavailable.

In addition to the drywell sump monitoring system described above, the discharge of each sump is monitored by an independent flow element. The measured flow rate from the flow element is integrated and recorded. A main control room alarm is also provided to indicate an excessive sump discharge rate measured via the flow element. This system, referred to as the "drywell floor drain flow totalizer", is not credited for drywell floor drain sump flow monitoring system operability.

REACTOR COOLANT SYSTEM

BASES

BACKGROUND (Continued)

The primary containment atmospheric gaseous radioactivity monitoring system continuously monitors the primary containment atmosphere for gaseous radioactivity levels. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water leakage, is annunciated in the main control room.

Condensate from the eight drywell air coolers is routed to the drywell floor drain sump and is monitored by a series of flow transmitters that provide indication and alarms in the main control room. The outputs from the flow transmitters are added together by summing units to provide a total continuous condensate drain flow rate. The high flow alarm setpoint is based on condensate drain flow rate in excess of 1 gpm over the currently identified preset leak rate. The drywell air cooler condensate flow rate monitoring system serves as an added indicator, but not quantifier, of RCS UNIDENTIFIED LEAKAGE (Ref. 4).

The drywell temperature and pressure monitoring systems provide an indirect method for detecting RCPB leakage. A temperature and/or pressure rise in the drywell above normal levels may be indicative of a reactor coolant or steam leakage (Ref. 5).

APPLICABLE SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. Leakage rate limits are set low enough to detect the leakage emitted from a single crack in the RCPB (Refs. 6 and 7).

A control room alarm allow the operators to evaluate the significance of the indicated leakage and, if necessary, shut down the reactor for further investigation and corrective action. The allowed leakage rates are well below the rates predicted for critical crack sizes (Ref. 7). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

LIMITING CONDITION FOR OPERATION (LCO)

This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of UNIDENTIFIED LEAKAGE are detected in time to allow actions to place the plant in a safe condition, when RCS leakage indicates possible RCPB degradation.

The LCO requires four instruments to be OPERABLE.

The required instrumentation to quantify UNIDENTIFIED LEAKAGE from the RCS consists of either the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump. For either system to be considered operable, the flow monitoring portion of the system must be operable. The identification of an increase in UNIDENTIFIED LEAKAGE will be delayed by the time required for the UNIDENTIFIED LEAKAGE to travel to the drywell floor drain sump and it may take longer than one hour to detect a 1 gpm increase in UNIDENTIFIED LEAKAGE, depending on the origin and magnitude of the leakage. This sensitivity is acceptable for containment sump monitor OPERABILITY.

The reactor coolant contains radioactivity that, when released to the primary containment, can be detected by the gaseous primary containment atmospheric radioactivity monitor. A radioactivity detection system is included for monitoring gaseous activities because of its sensitivity and rapid response to RCS leakage, but it has recognized limitations. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous primary

REACTOR COOLANT SYSTEM

BASES

LIMITING CONDITION FOR OPERATION (LCO) (Continued)

containment atmospheric radioactivity monitor to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous primary containment atmospheric radioactivity monitor is OPERABLE when it is capable of detecting a 1 gpm increase in UNIDENTIFIED LEAKAGE within 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors (Reference 9).

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the drywell floor drain sump monitoring system in combination with a gaseous primary containment atmospheric radioactivity monitor, a primary containment air cooler condensate flow rate monitoring system, and a primary containment pressure and temperature monitoring system provides an acceptable minimum.

APPLICABILITY

In OPERATIONAL CONDITIONS 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.3.2. This applicability is consistent with that for LCO 3.4.3.2.

ACTIONS

- A. With the primary containment atmosphere gaseous monitoring system inoperable, grab samples of the primary containment atmosphere must be taken and analyzed to provide periodic leakage information. [Provided a sample is obtained and analyzed once every 12 hours, the plant may be operated for up to 30 days to allow restoration of the radioactivity monitoring system. The plant may continue operation since other forms of drywell leakage detection are available.]

The 12 hours interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time for Restoration recognizes other forms of leakage detection are available.

- B. With required drywell sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage at the required 1 gpm/hour sensitivity. However, the primary containment atmospheric gaseous monitor [and the primary containment air cooler condensate flow rate monitor] will provide indication of changes in leakage.

With required drywell sump monitoring system inoperable, drywell condensate flow rate monitoring frequency increased from 12 to every 8 hours, and UNIDENTIFIED LEAKAGE and total leakage being determined every 8 hours (Ref: SR 4.4.3.2.1.b) operation may continue for 30 days. To the extent practical, the surveillance frequency change associated with the drywell condensate flow rate monitoring system, makes up for the loss of the drywell floor drain sump monitoring system which had a normal surveillance requirement to monitor leakage every 8 hours. Also note that in this instance, the drywell floor drain tank flow totalizer will be used to comply with SR 4.4.3.2.1.b. The 30 day Completion Time of the required ACTION is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

- C. With the required primary containment air cooler condensate flow rate monitoring system inoperable, SR 4.4.3.1.a must be performed every 8 hours to provide periodic information of activity in the primary containment at a more frequent interval than the routine frequency of every 12 hours. The 8 hour interval provides periodic information that is adequate to detect leakage and recognizes that other forms of leakage detection are available. The required ACTION has been clarified to state

REACTOR COOLANT SYSTEM

BASES

ACTIONS (Continued)

that the additional surveillance requirement is not applicable if the required primary containment atmosphere gaseous radioactivity monitoring system is also inoperable. Consistent with SR 4.0.3, surveillances are not required to be performed on inoperable equipment. In this case, ACTION Statement A. and E. requirements apply.

- D. With the primary containment pressure and temperature monitoring system inoperable, operation may continue for up to 30 days given the system's indirect capability to detect RCS leakage. However, other more limiting Tech Spec requirements associated with the primary containment pressure/temperature monitoring system will still apply.
- E. With both the primary containment atmosphere gaseous radioactivity monitor and the primary containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the drywell floor drain sump monitor and the drywell pressure/temperature instrumentation. This condition does not provide the required diverse means of leakage detection. The required ACTION is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period. While the primary containment atmosphere gaseous radioactivity monitor is INOPERABLE, primary containment atmospheric grab samples will be taken and analyzed every 12 hours since ACTION Statement A. requirements also apply.
- F. With the drywell floor drain sump monitoring system inoperable and the drywell unit coolers condensate flow rate monitoring system inoperable, one of the two remaining means of detecting leakage is the primary containment atmospheric gaseous radiation monitor. The primary containment atmospheric gaseous radiation monitor typically cannot detect a 1 gpm leak within one hour when RCS activity is low. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the primary containment atmosphere must be taken and analyzed and monitoring of RCS leakage by administrative means must be performed every 12 hours to provide alternate periodic information.

Administrative means of monitoring RCS leakage include monitoring and trending parameters that may indicate an increase in RCS leakage. There are diverse alternative mechanisms from which appropriate indicators may be selected based on plant conditions. It is not necessary to utilize all of these methods, but a method or methods should be selected considering the current plant conditions and historical or expected sources of UNIDENTIFIED LEAKAGE. The administrative methods are the drywell cooling fan inlet/outlet temperatures, drywell equipment drain sump temperature indicator, drywell equipment drain tank hi temperature indicator, and drywell equipment drain tank flow indicator. These indications, coupled with the atmospheric grab samples, are sufficient to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

In addition to the primary containment atmospheric gaseous radiation monitor and indirect methods of monitoring RCS leakage, the primary containment pressure and temperature monitoring system is also available to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

REACTOR COOLANT SYSTEM

BASES

ACTIONS (Continued)

The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to regain the intended leakage detection diversity. The 7-day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

- G. If any required ACTION of Conditions A, B, C, D, E or F cannot be met within the associated Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least HOT SHUTDOWN within 12 hours and COLD SHUTDOWN within the next 24 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the ACTIONS in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 4.4.3.1.a

This SR is for the performance of a CHANNEL CHECK of the required primary containment atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly.

SR 4.4.3.1.b

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

SR 4.4.3.1.c

This SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment.

SR 4.4.3.1.d

This SR provides a routine check of primary containment pressure and temperature for indirect evidence of RCS leakage.

REFERENCES

1. LGS UFSAR, Section 5.2.5.1.
2. Regulatory Guide 1.45, Revision 0, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.
3. LGS UFSAR, Section 5.2.5.2.1.3
4. LGS UFSAR, Section 5.2.5.2.1.4
5. LGS UFSAR, Section 5.2.5.2.1.1(2)
6. GEAP-5620, April 1968.
7. NUREG-75/067, October 1975.
8. LGS UFSAR, Section 5.2.5.6.
9. LGS UFSAR, Section 5.2.5.2.1.5

REACTOR COOLANT SYSTEM

BASES

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified, the reactor will be shutdown to allow further investigation and corrective action. The limit of 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period and the monitoring of drywell floor drain sump and drywell equipment drain tank flow rate at least once every eight (8) hours conforms with NRC staff positions specified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," as revised by NRC Safety Evaluation dated March 6, 1990. The ACTION requirement for the 2 gpm increase in UNIDENTIFIED LEAKAGE limit ensures that such leakage is identified or a plant shutdown is initiated to allow further investigation and corrective action. Separating the sources of LEAKAGE (i.e., LEAKAGE from an identified source versus LEAKAGE from an unidentified source) is necessary for prompt identification of potentially adverse conditions, assessment of the safety significance, and corrective action. Once identified, reactor operation may continue dependent upon the impact on total leakage.

PPRESSURE BOUNDARY LEAKAGE is prohibited as the leak itself could cause further reactor coolant pressure boundary deterioration, resulting in higher leakage. If PRESSURE BOUNDARY LEAKAGE exists, the affected component, pipe, or vessel must be isolated from the reactor coolant system by a closed manual valve, closed and deactivated automatic valve, blind flange, or check valve within 4 hours. While in this condition, structural integrity of the system should be considered because the structural integrity of the part of the system within the isolation boundary must be maintained under all licensing basis conditions, including consideration of the potential for further degradation of the isolated location. Normal leakage past the isolation device is acceptable as it will limit reactor coolant system leakage and is included in the IDENTIFIED LEAKAGE or UNIDENTIFIED LEAKAGE. This ACTION is necessary to prevent further deterioration of the reactor coolant pressure boundary. If the ACTION cannot be completed in the required time, then the reactor will be shutdown to allow further investigation and corrective action.

The function of Reactor Coolant System Pressure Isolation Valves (PIVs) is to separate the high pressure Reactor Coolant System from an attached low pressure system. The ACTION requirements for pressure isolation valves are used in conjunction with the system specifications for which PIVs are listed in The Technical Requirements Manual and with primary containment isolation valve requirements to ensure that plant operation is appropriately limited.

The Surveillance Requirements for the RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valves is not included in any other allowable operational leakage specified in Section 3.4.3.2.

3/4.4.4 (Deleted) INFORMATION FROM THIS SECTION RELOCATED TO THE TRM

REACTOR COOLANT SYSTEM

BASES

3/4.4.5 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the 2-hour thyroid and whole body doses resulting from a main steam line failure outside the containment during steady state operation will not exceed small fractions of the dose guidelines of 10 CFR Part 100. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters, such as SITE BOUNDARY location and meteorological conditions, were not considered in this evaluation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity greater than 0.2 microcurie per gram DOSE EQUIVALENT I-131, but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. This action is modified by a Note that permits the use of the provisions of Specification 3.0.4.c. This allowance permits entry into the applicable OPERATIONAL CONDITION (S) while relying on the ACTION requirements. Operation with specific activity levels exceeding 0.2 microcurie per gram DOSE EQUIVALENT I-131 but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131 must be restricted since these activity levels increase the 2-hour thyroid dose at the SITE BOUNDARY following a postulated steam line rupture.

Closing the main steam line isolation valves prevents the release of activity to the environs should a steam line rupture occur outside containment. The surveillance requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in Section 3.9 of the FSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

REACTOR COOLANT SYSTEM

BASES

PRESSURE/TEMPERATURE LIMITS (Continued)

The operating limit curves specified in the PTLR are derived from the fracture toughness requirements of 10 CFR 50 Appendix G and ASME Code Section XI, Appendix G. The curves are based on the RT_{NDT} and stress intensity factor information for the reactor vessel components. Fracture toughness limits and the basis for compliance are more fully discussed in FSAR Chapter 5, Paragraph 5.3.1.5, "Fracture Toughness."

The reactor vessel materials have been tested to determine their initial RT_{NDT} . The results of these tests are specified in the PTLR. Reactor operation and resultant fast neutron, E greater than 1 MeV, irradiation will cause an increase in the RT_{NDT} . Therefore, an adjusted reference temperature, based upon the fluence, nickel content and copper content of the material in question, can be predicted using the PTLR and the recommendations of Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." The pressure/temperature limit curves specified in the PTLR include an assumed shift in the RT_{NDT} for the conditions at 57 EFPY.

The pressure-temperature limit lines specified in the PTLR for reactor criticality and for inservice leak and hydrostatic testing have been provided to assure compliance with the minimum temperature requirements of Appendix G to 10 CFR Part 50 for reactor criticality and for inservice leak and hydrostatic testing.

REACTOR COOLANT SYSTEM

BASES

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

Double isolation valves are provided on each of the main steam lines to minimize the potential leakage paths from the containment in case of a line break. Only one valve in each line is required to maintain the integrity of the containment, however, single failure considerations require that two valves be OPERABLE. The surveillance requirements are based on the operating history of this type valve. The maximum closure time has been selected to contain fission products and to ensure the core is not uncovered following line breaks. The minimum closure time is consistent with the assumptions in the safety analyses to prevent pressure surges.

3/4.4.8 (DELETED)

3/4.4.9 RESIDUAL HEAT REMOVAL

The RHR system is required to remove decay heat and sensible heat in order to maintain the temperature of the reactor coolant. RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR System can provide the required decay heat removal capability. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the associated recirculation loop or to the reactor via the low pressure coolant injection pathway. The RHR heat exchangers transfer heat to the RHR Service Water System. The RHR shutdown cooling mode is manually controlled.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. In HOT SHUTDOWN condition, the requirement to maintain OPERABLE two (2) independent RHR shutdown cooling subsystems means that each subsystem considered OPERABLE must be associated with a different heat exchanger loop, i.e., the "A" RHR heat exchanger with the "A" RHR pump or the "C" RHR pump, and the "B" RHR heat exchanger with the "B" RHR pump or the "D" RHR pump are two (2) independent RHR shutdown cooling subsystems. Only one (1) of the two (2) RHR pumps associated with each RHR heat exchanger loop is

REACTOR COOLANT SYSTEM

BASES

3/4.4.9 RESIDUAL HEAT REMOVAL (Continued)

required to be OPERABLE for that independent subsystem to be OPERABLE. During COLD SHUTDOWN and REFUELING conditions, however, the subsystems not only have a common suction source, but are allowed to have a common heat exchanger and common discharge piping. To meet the LCO of two (2) OPERABLE subsystems, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. Since the piping and heat exchangers are passive components, that are assumed not to fail, they are allowed to be common to both subsystems. Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one (1) subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Alternate decay heat removal methods are available to operators. These alternate methods of decay heat removal can be verified available either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration, and that a method of coolant mixing be operational. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensable gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to initially placing the system in operation during reactor shutdown. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System whose use is typically preceded by system piping flushes that disturb both the RHR pump suction and discharge piping. RHR Shutdown Cooling System is flushed and manually aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. In the event that RHR Shutdown Cooling is required for emergency service, the system operating procedures that align and start the RHR System in shutdown cooling mode include the flexibility to eliminate piping flushes while maintaining minimum requirements to ensure that the suction and discharge flow paths are sufficiently filled with water. The RHR Shutdown Cooling System surveillance is met through the performance of the operating procedures that initially place the RHR shutdown cooling sub-system in service.

This surveillance requirement is modified by a Note allowing sufficient time (12 hours) to align the RHR System for Shutdown Cooling operation after reactor dome pressure is less than the RHR cut-in permissive set point.

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3/4.5 EMERGENCY CORE COOLING SYSTEM

BASES

3/4.5.1 ECCS - OPERATING

The core spray system (CSS), together with the LPCI mode of the RHR system, is provided to assure that the core is adequately cooled following a loss-of-coolant accident and provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS. Management of gas voids is important to ECCS injection/spray subsystem OPERABILITY.

The CSS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the CSS will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. Four subsystems, each with one pump, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

The surveillance requirements provide adequate assurance that the LPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

The high pressure coolant injection (HPCI) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the reactor coolant system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCI system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HPCI system continues to operate until reactor vessel pressure is below the pressure at which CSS operation or LPCI mode of the RHR system operation maintains core cooling.

The capacity of the system is selected to provide the required core cooling. The HPCI pump is designed to deliver greater than or equal to 5600 gpm at reactor pressures between 1182 and 200 psig and is capable of delivering at least 5000 gpm between 1182 and 1205 psig. In the system's normal alignment, water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor, but no credit is taken in the safety analyses for the condensate storage tank water.

EMERGENCY CORE COOLING SYSTEM

BASES

ECCS - OPERATING (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. The HPCI system, and one LPCI subsystem, and/or one CSS subsystem out-of-service period of 8 hours ensures that sufficient ECCS, comprised of a minimum of one CSS subsystem, three LPCI subsystems, and all of the ADS will be available to 1) provide for safe shutdown of the facility, and 2) mitigate and control accident conditions within the facility. Alternatively, the out-of-service times described above can be determined in accordance with the Risk Informed Completion Time Program. A Note prohibits the application of Specification 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown.

During plant startup, when the HPCI surveillance test is being performed, HPCI is required to be tested within 12 hours of changing modes. The intent of this requirement is to verify operability prior to reaching any significant power. If HPCI is not successfully demonstrated operable within the 12-hour period, the reactor steam dome pressure must be reduced to less than 200 psig within the following 72 hours. The intent of the action is to hold pressure at a point where sufficient steam is available to test the pump; it does not permit power ascension to continue.

The ECCS injection/spray subsystem flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS injection/spray subsystems and may also prevent a water hammer, pump cavitation, and pumping of noncondensable gas into the reactor vessel.

Selection of ECCS injection/spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The ECCS injection/spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

EMERGENCY CORE COOLING SYSTEM

BASES

ECCS - OPERATING (Continued)

ECCS injection/spray subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.5.1.a.1.b is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety/relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls five selected safety-relief valves. The safety analysis assumes all five are operable. The allowed out-of-service time for one valve for up to fourteen days is determined in a similar manner to other ECCS subsystem out-of-service time allowances. Alternatively, the allowed out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

Verification that ADS accumulator gas supply header pressure is ≥ 90 psig ensures adequate gas pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator at least two valve actuations can occur with the drywell at 70% of design pressure. The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥ 90 psig is provided by the PCIG supply.

EMERGENCY CORE COOLING SYSTEM

BASES

3/4.5.2 - REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC)

Background:

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Applicable Safety Analysis:

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material to the environment should an unexpected draining event occur.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure (an event that creates a drain path through multiple vessel penetrations located below top of active fuel, such as loss of normal power or a single human error). It is assumed, based on engineering judgement, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Limiting Condition for Operation:

The RPV water level must be controlled in OPERATIONAL CONDITIONS 4 and 5 to ensure that if an unexpected draining event should occur, the reactor coolant water level remains above the top of the active irradiated fuel as required by Safety Limit 2.1.4.

The Limiting Condition for Operation (LCO) requires the DRAIN TIME of RPV water inventory to the TAF to be ≥ 36 hours. A DRAIN TIME of 36 hours is considered reasonable to identify and initiate action to mitigate unexpected draining of reactor coolant. An event that could cause loss of RPV water inventory and result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.4 and can be managed as part of normal plant operation.

One low pressure ECCS injection/spray subsystem is required to be OPERABLE and capable of being manually aligned and started from the control room to provide defense-in-depth should an unexpected draining event occur. OPERABILITY of the ECCS injection/spray subsystem includes any necessary valves, instrumentation, or controls needed to manually align and start the subsystem from the control room. A low pressure ECCS injection/spray subsystem consists of either one Core Spray System (CSS) subsystem or one Low Pressure Coolant Injection (LPCI) subsystem. Each CSS subsystem consists of two motor driven pumps, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV. Each LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV.

EMERGENCY CORE COOLING SYSTEM

BASES

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The LCO is modified by a note which allows a required LPCI subsystem to be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. This allowance is necessary since the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Because of the restrictions on DRAIN TIME, sufficient time will be available following an unexpected draining event to manually align and initiate LPCI subsystem operation to maintain RPV water inventory prior to the RPV water level reaching the TAF.

Applicability:

RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5. Requirements on water inventory control are contained in LCO 3.3.3.A, REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION, and LCO 3.5.2, REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC). RPV water inventory control is required to protect Safety Limit 2.1.4 which is applicable whenever irradiated fuel is in the reactor vessel.

Actions:

Action a. - If none of the required low pressure ECCS injection/spray subsystems are OPERABLE, one subsystem must be restored to OPERABLE status within 4 hours. In this condition, the LCO controls on DRAIN TIME minimize the possibility that an unexpected draining event could necessitate the use of the ECCS injection/spray subsystem; however, the defense-in-depth provided by the ECCS injection/spray subsystem is lost. The 4-hour allowed outage time for restoring the required low pressure ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considers the LCO controls on DRAIN TIME and the low probability of an unexpected draining event that would result in loss of RPV water inventory.

If the inoperable ECCS injection/spray subsystem is not restored to OPERABLE status within 4 hours, action must be initiated immediately to establish a method of water injection capable of operating without offsite electrical power. The method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The method of water injection may be manually initiated and may consist of one or more systems or subsystems, and must be able to access water inventory capable of maintaining the RPV water level above the TAF for ≥ 36 hours. If recirculation of injected water would occur, it may be credited in determining the necessary water volume.

Action b. - Deleted

Action c. - With the DRAIN TIME less than 36 hours but greater than or equal to 8 hours, compensatory measures should be taken to ensure the ability to implement mitigating actions should an unexpected draining event occur. Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

EMERGENCY CORE COOLING SYSTEM

BASES

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The secondary containment provides a controlled volume in which fission products can be contained, diluted, and processed prior to release to the environment. Verification of the capability to establish SECONDARY CONTAINMENT INTEGRITY in less than the DRAIN TIME is required. The required verification confirms actions to establish SECONDARY CONTAINMENT INTEGRITY are preplanned and necessary materials are available. SECONDARY CONTAINMENT INTEGRITY is considered established when one Standby Gas Treatment (SGT) subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment. Verification that SECONDARY CONTAINMENT INTEGRITY can be established must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Secondary containment penetration flow paths form a part of SECONDARY CONTAINMENT INTEGRITY. Verification of the capability to isolate each secondary containment penetration flow path in less than the DRAIN TIME is required. The required verification confirms actions to isolate secondary containment penetration flow paths are preplanned and necessary materials are available. Power operated valves are not required to receive automatic isolation signals if they can be closed manually within the required time. Verification that secondary containment penetration flow paths can be isolated must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

One SGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Verification of the capability to place one SGT subsystem in operation in less than the DRAIN TIME is required. The required verification confirms actions to place a SGT subsystem in operation are preplanned and necessary materials are available. Verification that a SGT subsystem can be placed in operation must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Action d. - With the DRAIN TIME less than 8 hours, mitigating actions are implemented in case an unexpected draining event should occur. Note that if the DRAIN TIME is less than 1 hour, the required Action e. to restore DRAIN TIME to 36 hours or greater is also applicable.

Immediate action to establish an additional method of water injection augmenting the ECCS injection/spray subsystem required by the LCO is required. The additional method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The note states that either the ECCS injection/spray subsystem or the additional method of water injection must be capable of operating without offsite electrical power. The additional method of water injection may be manually initiated and may consist of one or more systems or subsystems. The additional method of water injection must be able to access water inventory capable of being injected to maintain the RPV water level above the TAF for ≥ 36 hours. The additional method of water injection and the ECCS injection/spray subsystem may share all or part of the same water sources. If recirculation of injected water would occur, it may be credited in determining the required water volume.

Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

EMERGENCY CORE COOLING SYSTEM

BASES

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The secondary containment provides a control volume into which fission products can be contained, diluted, and processed prior to release to the environment. Actions to immediately establish SECONDARY CONTAINMENT INTEGRITY are required. With SECONDARY CONTAINMENT INTEGRITY established, one SGT subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment.

The secondary containment penetrations form a part of SECONDARY CONTAINMENT INTEGRITY. Actions to immediately verify that each secondary containment penetration flow path is isolated or to verify that it can be automatically or manually isolated from the control room are required.

One SGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Actions to immediately verify that at least one SGT subsystem is capable of being placed in operation are required. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Action e. - If the ACTIONS and associated allowed outage times are not met or if the DRAIN TIME is less than 1 hour, actions must be initiated immediately to restore the DRAIN TIME to ≥ 36 hours. In this condition, there may be insufficient time to respond to an unexpected draining event to prevent the RPV water inventory from reaching the TAF. Note that ACTIONS are also applicable when DRAIN TIME is less than 1 hour.

Surveillance Requirements:

Surveillance Requirement (SR) 4.5.2.1 verifies that the DRAIN TIME of RPV water inventory to the TAF is ≥ 36 hours. The period of 36 hours is considered reasonable to identify and initiate action to mitigate draining of reactor coolant. Loss of RPV water inventory that would result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.4 and can be managed as part of normal plant operation.

The definition of DRAIN TIME states that realistic cross-sectional areas and drain rates are used in the calculation. A realistic drain rate may be determined using a single, step-wise, or integrated calculation considering the changing RPV water level during a draining event. For a control rod RPV penetration flow path with the control rod drive mechanism removed and not replaced with a blank flange, the realistic cross-sectional area is based on the control rod blade seated in the control rod guide tube. If the control rod blade will be raised from the penetration to adjust or verify seating of the blade, the exposed cross-sectional area of the RPV penetration flow path is used.

The definition of DRAIN TIME excludes from the calculation those penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are closed and administratively controlled, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths. A blank flange or other bolted device must be connected with a sufficient number of bolts to prevent draining. Normal or expected leakage from closed systems or past isolation devices is permitted. Determination that a system is intact and closed or isolated must consider the status of branch lines.

The Residual Heat Removal (RHR) Shutdown Cooling System is only considered an intact closed system when misalignment issues (Reference 6) have been precluded by functional valve interlocks or by isolation devices; such that redirection of RPV water out of an RHR subsystem is precluded. Further, the RHR Shutdown Cooling System is only considered an intact closed system if its controls have not been transferred to Remote Shutdown, which disables the interlocks and isolation signals.

EMERGENCY CORE COOLING SYSTEM

BASES

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The exclusion of a single penetration flow path, or multiple penetration flow paths susceptible to a common mode failure, from the determination of DRAIN TIME should consider the effects of temporary alterations in support of maintenance (rigging, scaffolding, temporary shielding, piping plugs, freeze seals, etc.). If reasonable controls are implemented to prevent such temporary alterations from causing a draining event from a closed system or between the RPV and the isolation device, the effect of the temporary alterations on DRAIN TIME need not be considered. Reasonable controls include, but are not limited to, controls consistent with the guidance in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 4, NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," or commitments to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."

TS 4.0.1 requires SRs to be met between performances. Therefore, any changes in plant conditions that would change the DRAIN TIME requires that a new DRAIN TIME be determined.

SRs 4.5.2.2 and 4.5.2.3 - The minimum water level of 16 feet required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the CSS subsystem or LPCI subsystem pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, the required ECCS injection/spray subsystem is inoperable unless aligned to an OPERABLE CST.

The required CSS subsystem is OPERABLE if it can take suction from the CST, and the CST water level is sufficient to provide the required NPSH for the CSS pumps. Therefore, a verification that either the suppression pool water level is greater than or equal to 16 feet 0 inches or that a CSS subsystem is aligned to take suction from the CST and the CST contains greater than or equal to 135,000 available gallons of water, equivalent to a level of 29 feet 0 inches, ensures that the CSS subsystem can supply the required makeup water to the RPV.

SR 4.5.2.4 - The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the required ECCS injection/spray subsystems full of water ensures that the ECCS subsystem will perform properly. This may also prevent a water hammer following an ECCS actuation. One acceptable method of ensuring that the lines are full is to vent at the high points.

SR 4.5.2.5 - DELETED

SR 4.5.2.6 - Verifying that the required ECCS injection/spray subsystem can be manually aligned, and the pump started and operated for at least 10 minutes demonstrates that the subsystem is available to mitigate a draining event. This surveillance requirement is modified by two footnotes. The first states that testing the ECCS injection/spray subsystem may be done through the test return line to avoid overfilling the refueling cavity. The second states that credit for meeting the surveillance requirement may be taken for normal system operation that satisfies the surveillance requirement, such as using the RHR mode of LPCI for greater than or equal to 10 minutes. The minimum operating time of 10 minutes was based on engineering judgement.

SR 4.5.2.7 - Verifying that each valve credited for automatically isolating a penetration flow path actuates to the isolation position on an actual or simulated RPV water level isolation signal is required to prevent RPV water inventory from dropping below the TAF should an unexpected draining event occur.

EMERGENCY CORE COOLING SYSTEM

BASES

RPV WATER INVENTORY CONTROL (WIC) (Continued)

SR 4.5.2.8 - This surveillance verifies that a required CSS subsystem or LPCI subsystem can be manually aligned and started from the control room, including any necessary valve alignment, instrumentation, or controls, to transfer water from the suppression pool or CST to the RPV.

The Surveillance Frequencies in the above SRs are controlled under the Surveillance Frequency Controlled Program.

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.
2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.
3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.
4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.
5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.
6. General Electric Service Information Letter No. 388, "RHR Valve Misalignment During Shutdown Cooling Operation for BWR 3/4/5/6," February 1983.

EMERGENCY CORE COOLING SYSTEM

BASES

3/4.5.3 SUPPRESSION CHAMBER

The suppression chamber is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCI, CS and LPCI systems in the event of a LOCA. This limit on suppression chamber minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression chamber in OPERATIONAL CONDITION 1, 2, or 3 is also required by Specification 3.6.2.1.

3/4.6 CONTAINMENT SYSTEMS

BASES

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

3/4.6.1.2 PRIMARY CONTAINMENT LEAKAGE

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value calculated in the safety analyses at the design basis LOCA maximum peak containment pressure of 44 psig, Pa. As an added conservatism, the measured overall integrated leakage rate (Type A Test) is further limited to less than or equal to 0.75 La during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

Operating experience with the main steam line isolation valves has indicated that degradation has occasionally occurred in the leak tightness of the valves; therefore the special requirement for testing these valves.

The surveillance testing for measuring leakage rates is consistent with the Primary Containment Leakage Rate Testing Program.

Limerick has an approved license amendment to implement 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors", and may voluntarily comply with the treatment requirements of 10 CFR 50.69 as an alternative to compliance with the Type B and Type C leakage testing requirements of 10 CFR 50, Appendix J for Risk-Informed Safety Classification (RISC) RISC-3 or RISC-4 penetrations and valves meeting the following criteria:

- A. Containment penetrations that are either 1-inch nominal size or less, or continuously pressurized.
- B. Containment isolation valves that meet one or more of the following criteria.
 - 1. The valve is required to be open under accident conditions to prevent or mitigate core damage events;
 - 2. The valve is normally closed and in a physically closed, water-filled system;
 - 3. The valve is in a physically closed system whose piping pressure rating exceeds the containment design pressure rating and is not connected to the reactor coolant pressure boundary; or
 - 4. The valve is 1-inch nominal size or less.

RISC-3 penetrations and valves that meet the criteria above may be removed from the scope of the Primary Containment Leakage Rate Testing Program, as implemented by Technical Specifications 3.6.1, 4.6.1 and 6.8.4.g. Alternative Treatment will be implemented in accordance with the requirements of 10 CFR 50.69(d).

3/4.6 CONTAINMENT SYSTEMS

BASES

3/4.6.1.3 PRIMARY CONTAINMENT AIR LOCK

The limitations on closure and leak rate for the primary containment air lock are required to meet the restrictions on PRIMARY CONTAINMENT INTEGRITY and the Primary Containment Leakage Rate Testing Program. Only one closed door in the air lock is required to maintain the integrity of the containment.

3/4.6.1.4 MSIV LEAKAGE ALTERNATE DRAIN PATHWAY

Calculated doses resulting from the maximum leakage allowances for the main steamline isolation valves in the postulated LOCA situations will not exceed the criteria of 10 CFR Part 100 guidelines, provided the main steam line system from the isolation valves up to and including the turbine condenser remains intact. Operating experience has indicated that degradation has occasionally occurred in the leak tightness of the MSIVs such that the specified leakage requirements have not always been continuously maintained. The requirement for the MSIV Leakage Alternate Drain Pathway serves to reduce the offsite dose.

CONTAINMENT SYSTEMS

BASES

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum calculated pressure in the event of a LOCA. A visual inspection in accordance with the Primary Containment Leakage Rate Testing Program is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the calculated containment peak pressure does not exceed the design pressure of 55 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5.0 psid. The limit of - 1.0 to + 2.0 psig for initial containment pressure will limit the total pressure to ≤ 44 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions and is consistent with the safety analysis.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The drywell and suppression chamber purge supply and exhaust isolation valves are required to be closed during plant operation except as required for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. Limiting the use of the drywell and suppression chamber purge system to specific criteria is imposed to protect the integrity of the SGTS filters. Analysis indicates that should a LOCA occur while this pathway is being utilized, the associated pressure surge through the (18 or 24") purge lines will adversely affect the integrity of SGTS. This condition is not imposed on the 1 and 2 inch valves used for pressure control since a surge through these lines does not threaten the operability of SGTS.

Surveillance requirement 4.6.1.8 ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by a Note stating that primary containment purge valves are only required to be closed in OPERATIONAL CONDITIONS 1, 2 and 3. The SR is also modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 or 24 inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time.

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CONTAINMENT SYSTEMS

BASES

3/4.6.2 DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure of 55 psig during primary system blowdown from full operating pressure. Management of gas voids is important to Suppression Pool Cooling/Spray Subsystem OPERABILITY.

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from rated conditions. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss-of-coolant accident, the pressure of the suppression chamber air space must not exceed 55 psig. The design volume of the suppression chamber, water and air, was obtained by considering that the total volume of reactor coolant is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in this specification, suppression pool pressure during the design basis accident is below the design pressure. Maximum water volume of 134,600 ft³ results in a downcomer submergence of 12'3" and the minimum volume of 122,120 ft³ results in a submergence approximately 2'3" less. The majority of the Bodega tests were run with a submerged length of 4 feet and with complete condensation. Thus, with respect to the downcomer submergence, this specification is adequate. The maximum temperature at the end of the blowdown tested during the Humboldt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperature above 170°F.

Should it be necessary to make the suppression chamber inoperable, this shall only be done as specified in Specification 3.5.3.

Under full power operating conditions, blowdown through safety/relief valves assuming an initial suppression chamber water temperature of 95°F results in a bulk water temperature of approximately 140°F immediately following blowdown which is below the 190°F bulk temperature limit used for complete condensation via T-quencher devices. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is no dependency on containment overpressure during the accident injection phase. If both RHR loops are used for containment cooling, there is no dependency on containment overpressure for post-LOCA operations.

CONTAINMENT SYSTEMS

BASES

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

RHR Suppression Pool Cooling/Spray subsystem piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR suppression pool subsystems and may also prevent water hammer and pump cavitation.

Selection of RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR Suppression Pool Cooling/Spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

One of the surveillance requirements for the suppression pool cooling (SPC) mode of the RHR system is to demonstrate that each RHR pump develops a flow rate ³10,000 gpm while operating in the SPC mode with flow through the heat exchanger and its associated closed bypass valve, ensuring that pump performance has not degraded during the cycle and that the flow path is operable. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component operability, trend performance and detect incipient failures by indicating abnormal performance. The RHR heat exchanger bypass valve is used for adjusting flow through the heat exchanger, and is not designed to be a tight shut-off valve. With the bypass valve closed, a portion of the total flow still travels through the bypass, which

CONTAINMENT SYSTEMS

BASES

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

can affect overall heat transfer. However, no heat transfer performance requirement of the heat exchanger is intended by the current Technical Specification surveillance requirement. This is confirmed by the lack of any flow requirement for the RHRSW system in Technical Specifications Section 3/4.7.1. Verifying an RHR flowrate through the heat exchanger does not demonstrate heat removal capability in the absence of a requirement for RHRSW flow. LGS does perform heat transfer testing of the RHR heat exchangers as part of its response to Generic Letter 89-13, which verified the commitment to meet the requirements of GDC 46.

Experimental data indicate that excessive steam condensing loads can be avoided if the peak local temperature of the suppression pool is maintained below 200°F during any period of relief valve operation for T-quencher devices. Specifications have been placed on the envelope of reactor operating conditions so that the reactor can be depressurized in a timely manner to avoid the regime of potentially high suppression chamber loadings.

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitoring these parameters daily is sufficient to establish any temperature trends. By requiring the suppression pool temperature to be frequently recorded during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken.

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

During a LOCA, potential leak paths between the drywell and suppression chamber airspace could result in excessive containment pressures, since the steam flow into the airspace would bypass the heat sink capabilities of the chamber. Potential sources of bypass leakage are the suppression chamber-to-drywell vacuum breakers (VBs), penetrations in the diaphragm floor, and cracks in the diaphragm floor and/or liner plate and downcomers located in the suppression chamber airspace. The containment pressure response to the postulated bypass leakage can be mitigated by manually actuating the suppression chamber sprays. An analysis was performed for a design bypass leakage area of A/\sqrt{k} equal to 0.0500 ft² to verify that the operator has sufficient time to initiate the sprays prior to exceeding the containment design pressure of 55 psig. The limit of 10% of the design value of 0.0500 ft² ensures that the design basis for the steam bypass analysis is met

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CONTAINMENT SYSTEMS

BASES

DEPRESSURIZATION SYSTEMS (Continued)

The drywell-to-suppression chamber bypass test at a differential pressure of at least 4.0 psi verifies the overall bypass leakage area for simulated LOCA conditions is less than the specified limit. For those outages where the drywell-to-suppression chamber bypass leakage test is not conducted, the VB leakage test verifies that the VB leakage area is less than the bypass limit, with a 76% margin to the bypass limit to accommodate the remaining potential leakage area through the passive structural components. Previous drywell-to-suppression chamber bypass test data indicates that the bypass leakage through the passive structural components will be much less than the 76% margin. The VB leakage limit, combined with the negligible passive structural leakage area, ensures that the drywell-to-suppression chamber bypass leakage limit is met for those outages for which the drywell-to-suppression chamber bypass test is not scheduled.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The scram discharge volume vent and drain valves serve a dual function, one of which is primary containment isolation. Since the other safety functions of the scram discharge volume vent and drain valves would not be available if the normal PCIV actions were taken, actions are provided to direct the user to the scram discharge volume vent and drain operability requirements contained in Specification 3.1.3.1. However, since the scram discharge volume vent and drain valves are PCIVs, the Surveillance Requirements of Specification 4.6.3 still apply to these valves.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.6.3 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

Primary containment isolation valves governed by this Technical Specification are identified in Table 3.6.3-1 of the TRM.

This Surveillance Requirement requires a demonstration that a representative sample of reactor instrument line excess flow check valves (EFCVs) is OPERABLE by verifying that the valve actuates to the isolation position on a simulated instrument line break signal. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested in accordance with the Surveillance Frequency Control Program. In addition, the EFCVs in the sample are representative of the various plant configurations, models, sizes, and operating environments. This ensures that any potentially common problem with a specific type or application of EFCV is detected at the earliest possible time. This Surveillance Requirement provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during a postulated instrument line break event. Furthermore, any EFCV failures will be evaluated to determine if additional testing in the test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint. For some EFCVs, this Surveillance can be performed with the reactor at power.

CONTAINMENT SYSTEMS

BASES

3/4.6.4 VACUUM RELIEF

Vacuum relief valves are provided to equalize the pressure between the suppression chamber and drywell. This system will maintain the structural integrity of the primary containment under conditions of large differential pressures.

The vacuum breakers between the suppression chamber and the drywell must not be inoperable in the open position since this would allow bypassing of the suppression pool in case of an accident. Two pairs of valves are required to protect containment structural integrity. There are four pairs of valves (three to provide minimum redundancy) so that operation may continue for up to 72 hours or in accordance with the Risk Informed Completion Time Program with no more than two pairs of vacuum breakers inoperable in the closed position.

Each vacuum breaker valve's position indication system is of great enough sensitivity to ensure that the maximum steam bypass leakage coefficient of

$$\frac{A}{\sqrt{k}} = 0.05 \text{ ft}^2$$

for the vacuum relief system (assuming one valve fully open) will not be exceeded.

CONTAINMENT SYSTEMS

BASES

3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Enclosure and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a vacuum in the reactor enclosure secondary containment with the standby gas treatment system in accordance with the Surveillance Frequency Control Program, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the reactor enclosure recirculation system and the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting SITE BOUNDARY and Control Room radiation doses associated with containment leakage. The operation of these systems and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analysis. Provisions have been made to continuously purge the filter plenums with instrument air when the filters are not in use to prevent buildup of moisture on the adsorbers and the HEPA filters.

As a result of the Alternative Source Term (AST) project, secondary containment integrity of the refueling area is not required during certain conditions when handling irradiated fuel or during CORE ALTERATIONS and alignment of the Standby Gas Treatment System to the refueling area is not required. The control room dose analysis for the Fuel Handling Accident (FHA) is based on unfiltered releases from the South Stack and therefore, does not require the Standby Gas Treatment System to be aligned to the refueling area.

However, when handling RECENTLY IRRADIATED FUEL, secondary containment integrity of the refueling area is required and alignment of the Standby Gas Treatment System to the refueling area is required. The AST fuel handling analysis does not include an accident involving RECENTLY IRRADIATED FUEL or an accident involving draining the reactor vessel.

The Standby Gas Treatment System is required to be OPERABLE when handling irradiated fuel, handling RECENTLY IRRADIATED FUEL and during CORE ALTERATIONS. Fuel Handling Accident releases from the North Stack must be filtered through the Standby Gas Treatment System to maintain control room doses within regulatory limits. The OPERABILITY of the Standby Gas Treatment System assures that releases, if made through the North Stack, are filtered prior to release.

CONTAINMENT SYSTEMS

BASES

SECONDARY CONTAINMENT (Continued)

Surveillances 4.6.5.1.1.a and 4.6.5.1.2.a are each modified by a footnote (*) which states the surveillance is not required to be met for up to 4 hours if an analysis demonstrates that one standby gas treatment subsystem remains capable of establishing the required secondary containment vacuum. Use of the footnote is expected to be infrequent but may be necessitated by situations in which secondary containment vacuum may be less than the required containment vacuum, such as, but not limited to, wind gusts or failure or change of operating normal ventilation subsystems. These conditions do not indicate any change in the leak tightness of the secondary containment boundary. The analysis should consider the actual conditions (equipment configuration, temperature, atmospheric pressure, wind conditions, measured secondary containment vacuum, etc.) to determine whether, if an accident requiring secondary containment to be OPERABLE were to occur, one train of standby gas treatment could establish the assumed secondary containment vacuum within the time assumed in the accident analysis. If so, the surveillance may be considered met for a period up to 4 hours. The 4-hour limit is based on the expected short duration of the situations when the footnote would be applied.

Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 require verifying that one secondary containment personnel access door in each access opening is closed which provides adequate assurance that exfiltration from the secondary containment will not occur. An access opening contains at least one inner and one outer door. The intent is to not breach the secondary containment, which is achieved by maintaining the inner or outer personnel access door closed. Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 provide an allowance for brief, inadvertent, simultaneous openings of redundant secondary containment personnel access doors for normal entry and exit conditions.

Although the safety analyses assumes that the reactor enclosure secondary containment draw down time will take 930 seconds, these surveillance requirements specify a draw down time of 916 seconds. This 14 second difference is due to the diesel generator starting and sequence loading delays which is not part of this surveillance requirement.

The reactor enclosure secondary containment draw down time analyses assumes a starting point of 0.25 inch of vacuum water gauge and worst case SGTS dirty filter flow rate of 2800 cfm. The surveillance requirements satisfy this assumption by starting the drawdown from ambient conditions and connecting the adjacent reactor enclosure and refueling area to the SGTS to split the exhaust flow between the three zones and verifying a minimum flow rate of 2800 cfm from the test zone. This simulates the worst case flow alignment and verifies adequate flow is available to drawdown the test zone within the required time. The Technical Specification Surveillance Requirement 4.6.5.3.b.3 is intended to be a multi-zone air balance verification without isolating any test zone.

The SGTS is common to Unit 1 and 2 and consists of two independent subsystems. The power supplies for the common portions of the subsystems are from Unit 1 safeguard busses, therefore the inoperability of these Unit 1 supplies are addressed in the SGTS ACTION statements in order to ensure adequate onsite power sources to SGTS for its Unit 2 function during a loss of offsite power event. The allowable out of service times are consistent with those in the Unit 1 Technical Specifications for SGTS and AC electrical power supply out of service condition combinations.

CONTAINMENT SYSTEMS

BASES

SECONDARY CONTAINMENT (Continued)

The SGTS fans are sized for three zones and therefore, when aligned to a single zone or two zones, will have excess capacity to more quickly drawdown the affected zones. There is no maximum flow limit to individual zones or pairs of zones and the air balance and drawdown time are verified when all three zones are connected to the SGTS.

The three zone air balance verification and drawdown test will be done after any major system alteration, which is any modification which will have an effect on the SGTS flowrate such that the ability of the SGTS to drawdown the reactor enclosure to greater than or equal to 0.25 inch of vacuum water gage in less than or equal to 916 seconds could be affected.

The field tests for bypass leakage across the SGTS charcoal adsorber and HEPA filter banks are performed at a flow rate of $5764 \pm 10\%$ cfm. The laboratory analysis performed on the SGTS carbon samples will be tested at a velocity of 66 fpm based on the system residence time.

The SGTS filter train pressure drop is a function of air flow rate and filter conditions. Surveillance testing is performed using either the SGTS or drywell purge fans to provide operating convenience.

Each reactor enclosure secondary containment zone and refueling area secondary containment zone is tested independently to verify the design leak tightness. A design leak tightness of 2500 cfm or less for each reactor enclosure and 764 cfm or less for the refueling area at a 0.25 inch of vacuum water gage will ensure that containment integrity is maintained at an acceptable level if all zones are connected to the SGTS at the same time.

The Reactor Enclosure Secondary Containment Automatic Isolation Valves and Refueling Area Secondary Containment Automatic Isolation Valves can be found in the UFSAR.

The post-LOCA offsite dose analysis assumes a reactor enclosure secondary containment post-draw down leakage rate of 2500 cfm and certain post-accident X/Q values. While the post-accident X/Q values represent a statistical interpretation of historical meteorological data, the highest ground level wind speed which can be associated with these values is 7 mph (Pasquill-Gifford stability Class G for a ground level release). Therefore, the surveillance requirement assures that the reactor enclosure secondary containment is verified under meteorological conditions consistent with the assumptions utilized in the design basis analysis. Reactor Enclosure Secondary Containment leakage tests that are successfully performed at wind speeds in excess of 7 mph would also satisfy the leak rate surveillance requirements, since it shows compliance with more conservative test conditions.

CONTAINMENT SYSTEMS

BASES

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

The primary containment atmospheric mixing system is provided to ensure adequate mixing of the containment atmosphere to prevent localized accumulations of hydrogen and oxygen from exceeding the lower flammability limit during post-LOCA conditions.

All nuclear reactors must be designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration <4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen <4.0 v/o works together with Drywell Hydrogen Mixing System to provide redundant and diverse methods to mitigate events that produce hydrogen.

If oxygen concentration is ≥ 4.0 v/o at any time while operating in OPERATIONAL CONDITION 1 or 2, oxygen concentration must be restored to < 4.0 v/o within 72 hours. The 72 hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o because of the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

The provision of Specification 3.0.4.c is applicable. This allowance permits entry into the applicable OPERATIONAL CONDITION(S) while relying on the Actions. This allowance is acceptable because inerting the primary containment prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup, after entering OPERATIONAL CONDITIONS 1 and 2, and deinerted as soon as possible in the plant shutdown. It is acceptable to intentionally enter the Action prior to a shutdown in order to begin deinerting the primary containment prior to exiting the Applicability.

If oxygen concentration cannot be restored to within the limit within the required Completion Time, the plant must be brought to a OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, power must be reduced to HOT SHUTDOWN within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

3/4.7 PLANT SYSTEMS

BASES

3/4.7.1 SERVICE WATER SYSTEMS - COMMON SYSTEMS

The OPERABILITY of the service water systems ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

The RHRSW and ESW systems are common to Units 1 and 2 and consist of two independent subsystems each with two pumps. One pump per subsystem (loop) is powered from a Unit 1 safeguard bus and the other pump is powered from a Unit 2 safeguard bus. In order to ensure adequate onsite power sources to the systems during a loss of offsite power event, the inoperability of these supplies are restricted in system ACTION statements.

RHRSW is a manually operated system used for core and containment heat removal. Each of two RHRSW subsystems has one heat exchanger per unit. Each RHRSW pump provides adequate cooling for one RHR heat exchanger. By limiting operation with less than three OPERABLE RHRSW pumps with OPERABLE Diesel Generators, each unit is ensured adequate heat removal capability for the design scenario of LOCA/LOOP on one unit and simultaneous safe shutdown of the other unit.

Each ESW pump provides adequate flow to the cooling loads in its associated loop. With only two divisions of power required for LOCA mitigation of one unit and one division of power required for safe shutdown of the other unit, one ESW pump provides sufficient capacity to fulfill design requirements. ESW pumps are automatically started upon start of the associated Diesel Generators. Therefore, the allowable out of service times for OPERABLE ESW pumps and their associated Diesel Generators is limited to ensure adequate cooling during a loss of offsite power event. Alternatively, the allowable out-of-service times can be determined in accordance with the Risk Informed Completion Time Program.

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM

The OPERABILITY of the control room emergency fresh air supply system ensures that the control room will remain habitable for occupants during and following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. Constant purge of the system at 1 cfm is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less Total Effective Dose Equivalent. This limitation is consistent with the requirements of 10 CFR Part 50.67, Accident Source Term.

Since the Control Room Emergency Fresh Air Supply System is not credited for filtration in OPERATIONAL CONDITIONS 4 and 5, applicability to 4 and 5 is only required to support the Chlorine and Toxic Gas design basis isolation requirements.

The CREFAS is common to Units 1 and 2 and consists of two independent subsystems. The power supplies for the system are from Unit 1 Safeguard busses, therefore, the inoperability of these Unit 1 supplies are addressed in the CREFAS ACTION statements in order to ensure adequate onsite power sources to CREFAS during a loss of offsite power event. The allowable out of service

PLANT SYSTEMS

BASES

CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

times are consistent with those in the Unit 1 Technical Specifications for GREFAS and AC electrical power supply out of service condition combinations.

The Control Room Envelope (CRE) is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and other noncritical areas including adjacent support offices, toilet and utility rooms. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, ceiling, ducting, valves, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

In addition, the CREFAS System provides protection from radiation, smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 1). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 2).

In order for the CREFAS subsystems to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

PLANT SYSTEMS

BASES

CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

During the period that the CRE boundary is considered inoperable, action must be initiated immediately to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

SR 4.7.2.2 verifies the OPERABILITY of the CRE boundary by testing for unfiltered air leakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem Total Effective Dose Equivalent and the CRE occupants are protected from hazardous chemicals and smoke. SR 4.7.2.2 verifies that the unfiltered air leakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air leakage is greater than the assumed flow rate, Required Action 3.7.2.a.2 must be entered. Required Action 3.7.2.a.2.c allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 3) which endorses; with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 4). These compensatory measures may also be used as mitigating actions as required by Required Action 3.7.2.a.2.b. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 5). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope leakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

PLANT SYSTEMS

BASES

CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

REFERENCES

1. UFSAR Section 6.4
2. UFSAR Section 9.5
3. Regulatory Guide 1.196
4. NEI 99-03, "Control Room Habitability Assessment Guidance," June 2001.
5. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the emergency core cooling system equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure exceeds 150 psig. This pressure is substantially below that for which low pressure core cooling systems can provide adequate core cooling. Management of gas voids is important to RCIC System OPERABILITY.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2, and 3 when reactor vessel pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period. Alternatively, out-of-service time can be determined in accordance with the Risk Informed Completion Time Program. A Note prohibits the application of Specification 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable RCIC subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that RCIC will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown.

Surveillance requirement 4.7.3.c.2 is normally met using reactor steam to verify the system will develop a flow greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine in the range of 150 to 165 psig. As an alternative, Auxiliary Steam can be used for the low pressure RCIC testing prior to reactor startup.

During plant startup, when the RCIC surveillance test is being performed, RCIC is required to be tested within 12 hours of changing modes. The intent of this requirement is to verify operability prior to reaching any significant power. If RCIC is not successfully demonstrated operable within the 12-hour period, the reactor steam dome pressure must be reduced to less than 150 psig within the following 72 hours. The intent of the action is to hold pressure at a point where sufficient steam is available to test the pump; it does not permit power ascension to continue.

PLANT SYSTEMS

BASES

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM (Continued)

The RCIC System flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RCIC System and may also prevent water hammer, pump cavitation, and pumping of noncondensable gas into the reactor vessel.

Selection of RCIC System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RCIC System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RCIC System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.7.3.a.2 is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

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PLANT SYSTEMS

BASES

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PLANT SYSTEMS

BASES

3/4.7.5 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e., sealed sources within radiation monitoring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

PLANT SYSTEMS

BASES

SEALED SOURCE CONTAMINATION (Continued)

The testing frequency for start-up sources and fission detectors is based upon physical limitations in leak testing. For example, the Californium 252 start-up neutron source must be leak tested by the manufacturer remotely in a hot cell facility. Due to the physical design of this source, a six month frequency for contamination testing provides reasonable assurance that the radioactive material is properly contained.

PLANT SYSTEMS

BASES

3/4 7.6 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

PLANT SYSTEMS

BASES

3/4 7.8 MAIN TURBINE BYPASS SYSTEM

The required OPERABILITY of the main turbine bypass system is consistent with the assumptions of the feedwater controller failure analysis in the cycle specific transient analysis.

The main turbine bypass system is required to be OPERABLE to limit peak pressure in the main steam lines and to maintain reactor pressure within acceptable limits during events that cause rapid pressurization such that the Safety Limit MCPR is not exceeded. With the main turbine bypass system inoperable, continued operation is based on the cycle specific transient analysis which has been performed for the feedwater controller failure, maximum demand with bypass failure.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety-related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criterion 17 of Appendix A to 10 CFR Part 50.

An offsite power source consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E emergency bus or buses. The determination of the OPERABILITY of an offsite source of power is dependent upon grid and plant factors that, when taken together, describe the design basis calculation requirements for voltage regulation. The combination of these factors ensures that the offsite source(s), which provide power to the plant emergency buses, will be fully capable of supporting the equipment required to achieve and maintain safe shutdown during postulated accidents and transients.

The plant factors consist of the status of the Startup Transformer (#10 and #20) load tap changers (LTCs), the status of the Safeguard Transformer (#101 and #201) load tap changers (LTCs), and the alignment of emergency buses on the Safeguard Buses (101-Bus and 201-Bus). For an offsite source to be considered operable, both of its respective LTCs (#10 AND #101 for the source to the 101-Bus, #20 AND #201 for the source to the 201-Bus) must be in service, and in automatic. For the third offsite source (from 66 kV System) to be considered operable, the connected Safeguard Transformer (#101 or #201) LTC must be in service and in automatic. There is a dependency between the alignment of the emergency buses and the allowable post contingency voltage drop percentage.

The grid factors consist of actual grid voltage levels (real time) and the post trip contingency voltage drop percentage value.

The minimum offsite source voltage levels are established by the voltage regulation calculation. The transmission system operator (TSO) will notify LGS when an agreed upon limit is approached.

The post trip contingency percentage voltage drop is a calculated value determined by the TSO that would occur as a result of the tripping of one of the Limerick generators. The TSO will notify LGS when an agreed upon limit is exceeded. The voltage regulation calculation establishes the acceptable percentage voltage drop based upon plant configuration; the acceptable value is dependent upon plant configuration.

Due to the 20 Source being derived from the tertiary of the 4A and 4B transformer, its operability is influenced by both the 230 kV system and the 500 kV system. The 10 Source operability is only influenced by the 230 kV system.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The anticipated post trip contingency voltage drop for the 66 kV Source (Transformers 8A/8B) is calculated to be less than the 230 kV and 500 kV systems. This is attributed to the electrical distance between the output of the Limerick generators and the input to the 8A/8B transformers. Additionally, the Unit Auxiliary Buses do not transfer to the 8A/8B transformers; this provides margin to the calculated post trip contingency voltage drop limit.

There are various means of hardening the 10 and 20 Sources to obtain additional margin to the post trip contingency voltage drop limits. These means include, but are not limited to, source alignment of the 4 kV buses, preventing transfer of 13 kV buses, limiting transfer of selected 13 kV loads, and operation with 13 kV buses on the offsite sources. The specific post trip contingency voltage drop percentage limits for these alignments are identified in the voltage regulation calculation, and controlled via plant procedures. There are also additional restrictions that can be applied to these limits in the event that an LTC is taken to manual, or if the bus alignment is outside the Two Source rule set.

LGS unit post trip contingency voltage drop percentage calculations are performed by the PJM Energy Management System (EMS). The PJM EMS consists of a primary and backup system. LGS will be notified if the real time contingency analysis capability of PJM is lost. Upon receipt of this notification, LGS is to request PJM to provide an assessment of the current condition of the grid based on the tools that PJM has available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and whether the current condition of the grid is bounded by the grid studies previously performed for LGS.

Based on specific design analysis, variations to any of these parameters can be determined, usually at the sacrifice of another parameter, based on plant conditions. Specifics regarding these variations must be controlled by plant procedures or by operability determinations, backed by specific design calculations.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least two of the onsite A.C. and the corresponding D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss-of-offsite power and single failure of the other onsite A.C. or D.C. source. At least two onsite A.C. and their corresponding D.C. power sources and distribution systems providing power for at least two ECCS divisions (1 Core Spray loop, 1 LPCI pump and 1 RHR pump in suppression pool cooling) are required for design basis accident mitigation as discussed in UFSAR Table 6.3-3.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Onsite A.C. operability requirements for common systems such as CREFAS, SGTS, RHRSW and ESW are addressed in the appropriate system specification action statements.

A.C. Sources

As required by Specification 3.8.1.1, Action e, when one or more diesel generators are inoperable, there is an additional ACTION requirement to verify that all remaining required systems, subsystems, trains, components, and devices, that depend on the OPERABLE diesel generators as a source of emergency power, are also OPERABLE. The LPCI mode of the RHR system is considered a four train system, of which only two trains are required. The verification for LPCI is not required until two diesel generators are inoperable. This requirement is intended to provide assurance that a loss-of-offsite power event will not result in a complete loss of safety function of critical systems during the period when one or more of the diesel generators are inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

Specification 3.8.1.1, Action f, prohibits the application of Specification 3.0.4.b to an inoperable diesel generator. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable diesel generator subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

If it can be determined that the cause of the inoperable EDG does not exist on the remaining operable EDG(s), based on a common-mode evaluation, then the EDG start test (SR 4.8.1.1.2.a.4) does not have to be performed. If it cannot otherwise be determined that the cause of the initial inoperable EDG does not exist on the remaining EDG(s), then satisfactory performance of the start test suffices to provide assurance of continued operability of the remaining EDG(s). If the cause of the initial inoperability exists on the remaining operable EDG(s), the EDG(s) shall be declared inoperable upon discovery and the appropriate action statement for multiple inoperable EDGs shall be entered. In the event the inoperable EDG is restored to operable status prior to completing the EDG start test (SR 4.8.1.1.2.a.4) or common-mode failure evaluation as required in Specification 3.8.1.1, the plant corrective action program shall continue to evaluate the common-mode failure possibility. However, this continued evaluation is not subject to the time constraint imposed by the action statement. The provisions contained in the inoperable EDG action requirements that avoid unnecessary EDG testing are based on Generic Letter 93-05, "Line-Item Technical Specifications Improvement to Reduce Surveillance Requirements for Testing During Power Operation," dated September 27, 1993.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

The time, voltage, and frequency acceptance criteria specified for the EDG single largest post-accident load rejection test (SR 4.8.1.1.2.e.2) are derived from Regulatory Guide 1.9, Rev. 2, December 1979, recommendations. The test is acceptable if the EDG speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal, whichever is lower. This computes to be 66.5 Hz for the LGS EDGs. The RHR pump motor represents the single largest post-accident load. The 1.8 seconds specified is equal to 60% of the 3-second load sequence interval associated with sequencing the next load following the RHR pumps in response to an undervoltage on the electrical bus concurrent with a LOCA. This provides assurance that EDG frequency does not exceed predetermined limits and that frequency stability is sufficient to support proper load sequencing following a rejection of the largest single load.

D.C. Sources

With one division with one or two battery chargers inoperable (e.g., the voltage limit of 4.8.2.1.a.2 is not maintained), the ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Action a.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 18 hours, the battery will be restored to its fully charged condition (Action a.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 18 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 18 hours (Action a.2).

Action a.2 requires that the battery float current be verified for Divisions 1 and 2 as ≤ 2 amps, and for Divisions 3 and 4 as ≤ 1 amp. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 18 hour period the battery float current is not within limits this indicates there may be additional battery problems.

Action a.3 limits the restoration time for the inoperable battery charger to 7 days or in accordance with the Risk Informed Completion Time Program. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 days reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status. Alternatively, the allowable out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

With one or more cells in one or more batteries in one division < 2.07 V, the battery cell is degraded. Per Action b.1, within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (4.8.2.1.a.2) and of the overall battery state of charge by monitoring the battery float charge current (4.8.2.1.a.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, with one or more cells in one or more batteries < 2.07 V, continued operation is permitted for a limited period up to 24 hours.

Division 1 or 2 with float current > 2 amps, or Division 3 or 4 with float current > 1 amp, indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Per Action b.2, within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage.

Since Actions b.1 and b.2 only specify "perform," a failure of 4.8.2.1.a.1 or 4.8.2.1.a.2 acceptance criteria does not result in this Action not being met. However, if one of the Surveillance Requirements is failed the appropriate Action(s), depending on the cause of the failures, is also entered.

If the Action b.2 condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 18 hours is a reasonable time prior to declaring the battery inoperable.

With one or more batteries in one division with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, (i.e., greater than the minimum level indication mark), the battery still retains sufficient capacity to perform the intended function. Per Action b.3, within 31 days the minimum established design limits for electrolyte level must be re-established.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Action b.3 addresses this potential (as well as provisions in Specification 6.8.4.h, "Battery Monitoring and Maintenance Program"). Within 8 hours level is required to be restored to above the top of the plates. The Action requirement to verify that there is no leakage by visual inspection and the Specification 6.8.4.h item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the battery may have to be declared inoperable and the affected cell(s) replaced.

Per Action b.4, with one or more batteries in one division with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

Per Action b.5, with one or more batteries in more than one division with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that multiple divisions are involved. With multiple divisions involved, this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer restoration times specified for battery parameters on one division not within limits are therefore not appropriate, and the parameters must be restored to within limits on all but one division within 2 hours.

When any battery parameter is outside the allowances of Actions b.1, b.2, b.3, b.4, or b.5, sufficient capacity to supply the maximum expected load requirement is not ensured and a 2 hour restoration time is appropriate. Additionally, discovering one or more batteries in one division with one or more battery cells float voltage less than 2.07 V and float current greater than limits indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be restored within 2 hours.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

The surveillance requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Supplies, March 10, 1971, Regulatory Guide 1.137 "Fuel-Oil Systems for Standby Diesel Generators," Revision 1, October 1979 and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977 except for paragraphs C.2.a(3), C.2.c(1), C.2.c(2), C.2.d(3) and C.2.d(4), and the periodic testing will be performed in accordance with the Surveillance Frequency Control Program. The exceptions to Regulatory Guide 1.108 allow for gradual loading of diesel generators during testing and decreased surveillance test frequencies (in response to Generic Letter 84-15). The single largest post-accident load on each diesel generator is the RHR pump.

The Surveillance Requirement for removal of accumulated water from the fuel oil storage tanks is for preventive maintenance. The presence of water does not necessarily represent failure of the Surveillance Requirement, provided the accumulated water is removed during performance of the Surveillance. Accumulated water in the fuel oil storage tanks constitutes a collection of water at a level that can be consistently and reliably measured. The minimum level at which accumulated water can be consistently and reliably measured in the fuel oil storage tank sump is 0.25 inches. Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of accumulated water from the fuel storage tanks once every (31) days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137.

The surveillance requirements for demonstrating the OPERABILITY of the units batteries are in accordance with the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications."

Verifying battery float current while on float charge (4.8.2.1.a.1) is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450-1995.

This Surveillance Requirement states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of 4.8.2.1.a.2. When this float voltage is not maintained the Actions of LCO 3.8.2.1, Action b., are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limits are established based on the float voltage range and is not directly applicable when this voltage is not maintained.

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3/4.8 ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Verifying, per 4.8.2.1.a.2, battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the minimum float voltage established by the battery manufacturer (2.20 Vpc, average, or 132 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years).

Surveillance Requirements 4.8.2.1.b.1 and 4.8.2.1.c require verification that the cell float voltages are equal to or greater than 2.07 V.

The limit specified in 4.8.2.1.b.2 for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability.

Surveillance Requirement 4.8.2.1.b.3 verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60 degrees Fahrenheit). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity.

Surveillance Requirement 4.8.2.1.d.1 verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32, the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

Surveillance Requirement 4.8.2.1.d.1 requires that each battery charger be capable of supplying the amps listed for the specified charger at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. This time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

A battery service test, per 4.8.2.1.d.2, is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in the UFSAR.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

A battery performance discharge test (4.8.2.1.e and f) is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage. Degradation (as used in 4.8.2.1.f) is indicated when the battery capacity drops more than 10% from its capacity on the previous performance test, or is below 90% of the manufacturer's rating.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying 4.8.2.1.e and 4.8.2.1.f; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of 4.8.2.1.d.2.

ELECTRICAL POWER SYSTEMS

BASES

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

The RPS Electric Power Monitoring System is provided to isolate the RPS bus from the RPS/UPS inverter or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus from unacceptable voltage and frequency conditions. The essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and valve isolation logic.

The Allowable Values are derived from equipment design limits, corrected for calibration and instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection and include allowances for instrumentation uncertainties, calibration tolerances, and instrument drift.

The Allowable Values for the instrument settings are based on the RPS providing power within the design ratings of the associated RPS components (e.g., RPS logic, scram solenoids). The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels.

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3/4.9 REFUELING OPERATIONS

BASES

3/4.9.1 REACTOR MODE SWITCH

Locking the OPERABLE reactor mode switch in the Shutdown or Refuel position, as specified, ensures that the restrictions on control rod withdrawal and refueling platform movement during the refueling operations are properly activated. These conditions reinforce the refueling procedures and reduce the probability of inadvertent criticality, damage to reactor internals or fuel assemblies, and exposure of personnel to excessive radioactivity.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of at least two source range monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core. The minimum count rate is not required when sixteen or fewer fuel assemblies are in the core. During a typical core reloading, two, three or four irradiated fuel assemblies will be loaded adjacent to each SRM to produce greater than the minimum required count rate. Loading sequences are selected to provide for a continuous multiplying medium to be established between the required operable SRMs and the location of the core alteration. This enhances the ability of the SRMs to respond to the loading of each fuel assembly. During a core unloading, the last fuel to be removed is that fuel adjacent to the SRMs.

3/4.9.3 CONTROL ROD POSITION

The requirement that all control rods be inserted during other CORE ALTERATIONS ensures that fuel will not be loaded into a cell without a control rod.

3/4.9.4 DECAY TIME

The minimum requirement for reactor subcriticality prior to fuel movement ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the accident analyses.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity condition during movement of fuel within the reactor pressure vessel.

3/4.9 REFUELING OPERATIONS

BASES (Continued)

3/4.9.6 REFUELING PLATFORM

The OPERABILITY requirements ensure that (1) the refueling platform will be used for handling control rods and fuel assemblies within the reactor pressure vessel, (2) each hoist has sufficient load capacity for handling fuel assemblies and control rods, (3) the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations, and (4) inadvertent criticality will not occur due to fuel being loaded into a unrodded cell.

Inadvertent criticality is prevented by the refueling interlocks that block unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn or withdrawal of a rod from the core while the grapple is over the core and loaded with fuel). The hoist loaded values identified in Sections 4.9.6.1b and 4.9.6.1c support the refueling interlock logic by ensuring that the hoist fuel loaded switches function with a load lighter than the weight of a single fuel assembly in water. Load values represent fuel (load) on the grapple. The values of 485 +/- 50 pounds and 550 + 0, -115 pounds are both less than the weight of a single fuel assembly in water attached to the grapple. These load values ensure that as soon as a fuel assembly is grappled and lifted, the refueling interlocks (control rod block and bridge motion interlock) are enforced as required. The hoist load weighing system is compensated for mast weight to ensure that lifting of components other than fuel assemblies (e.g., blade guides) do not cause inadvertent control rod blocks or bridge motion stops.

3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE POOL

The restriction on movement of loads in excess of the nominal weight of a fuel assembly and associated lifting device over other fuel assemblies in the storage pool ensures that in the event this load is dropped 1) the activity release will be limited to that contained in a single fuel assembly, and 2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

3/4.9.8 and 3/4.9.9 WATER LEVEL - REACTOR VESSEL and WATER LEVEL - SPENT FUEL STORAGE POOL

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

3/4.9.10 CONTROL ROD REMOVAL

These specifications ensure that maintenance or repair of control rods or control rod drives will be performed under conditions that limit the probability of inadvertent criticality. The requirements for simultaneous removal of more than one control rod are more stringent since the SHUTDOWN MARGIN specification provides for the core to remain subcritical with only one control rod fully withdrawn.

3/4.9 REFUELING OPERATIONS

BASES (Continued)

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed by the RHR system to maintain adequate reactor coolant temperature.

RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR system provide decay heat removal. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System.

An OPERABLE RHR shutdown cooling subsystem consists of one (1) OPERABLE RHR pump, one (1) heat exchanger, and the associated piping and valves. The requirement for having one (1) RHR shutdown cooling subsystem OPERABLE ensures that 1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F, and 2) sufficient coolant circulation would be available through the reactor core to assure accurate temperature indication. Management of gas voids is important to RHR Shutdown Cooling Subsystem OPERABILITY.

The requirement to have two (2) RHR shutdown cooling subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange ensures that a single failure of the operating loop will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and 22 feet of water above the reactor vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR subsystem, adequate time is provided to initiate alternate methods capable of decay heat removal or emergency procedures to cool the core.

To meet the LCO of the two (2) subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. The two (2) subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Additionally, each shutdown cooling subsystem can provide the required decay heat removal capability; however, ensuring operability of the other shutdown cooling subsystem provides redundancy.

The required cooling capacity of an alternate method of decay heat removal should be ensured by verifying its capability to maintain or reduce reactor coolant temperature either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

3/4.9 REFUELING OPERATIONS

BASES

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION (Continued)

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensable gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to placing the system in operation when in OPCON 5. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System that is aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. An RHR Shutdown Cooling sub-system that is already in operation at the time of entry into the APPLICABILITY is OPERABLE. For an idle RHR Shutdown Cooling subsystem, the surveillance is met through the performance of the operating procedures that place the RHR Shutdown Cooling subsystem in service.

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Action "a", additional actions are required to minimize any potential fission product release to the environment. This includes ensuring Refueling Floor Secondary Containment is OPERABLE; one (1) Standby Gas Treatment subsystem is OPERABLE; and Secondary Containment isolation capability (i.e., one (1) Secondary Containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactive releases. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

If no RHR subsystem is in operation, an alternate method of coolant circulation is required to be established within one (1) hour. The Completion Time is modified such that one (1) hour is applicable separately for each occurrence involving a loss of coolant circulation.

3/4.10 SPECIAL TEST EXCEPTIONS

BASES

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

The requirement for PRIMARY CONTAINMENT INTEGRITY is not applicable during the period when open vessel tests are being performed during the low power PHYSICS TESTS.

3/4.10.2 ROD WORTH MINIMIZER

In order to perform the tests required in the technical specifications it is necessary to bypass the sequence restraints on control rod movement. The additional surveillance requirements ensure that the specifications on heat generation rates and shutdown margin requirements are not exceeded during the period when these tests are being performed and that individual rod worths do not exceed the values assumed in the safety analysis.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations with the vessel head removed requires additional restrictions in order to ensure that criticality does not occur. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

3/4.10.5 OXYGEN CONCENTRATION

Relief from the oxygen concentration specifications is necessary in order to provide access to the primary containment during the initial startup and testing phase of operation. Without this access the startup and test program could be restricted and delayed.

3/4.10.6 TRAINING STARTUPS

This special test exception permits training startups to be performed with the reactor vessel depressurized at low THERMAL POWER and temperature while controlling RCS temperature with one RHR subsystem aligned in the shutdown cooling mode in order to minimize contaminated water discharge to the radioactive waste disposal system.

3/4.10.7 SPECIAL INSTRUMENTATION - INITIAL CORE LOADING

This special test exception permits relief from the requirements for a minimum count rate while loading the first 16 fuel bundles to allow sufficient source-to-detector coupling such that minimum count rate can be achieved on an SRM. This is acceptable because of the significant margin to criticality while loading the initial 16 fuel bundles.

3/4.10 SPECIAL TEST EXCEPTIONS

BASES

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

This special test exception permits certain reactor coolant pressure tests to be performed in OPERATIONAL CONDITION 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) or plant temperature control capabilities during these tests require the pressure testing at temperatures greater than 200°F (normally corresponding to OPERATIONAL CONDITION 3). The additionally imposed OPERATIONAL CONDITION 3 requirements for SECONDARY CONTAINMENT INTEGRITY provide conservatism in response to an operational event.

Invoking the requirement for Refueling Area Secondary Containment Integrity along with the requirement for Reactor Enclosure Secondary Containment Integrity applies the requirements for Reactor Enclosure Secondary Containment Integrity to an extended area encompassing Zones 2 and 3. Core alterations and fuel handling are prohibited in this secondary containment configuration. Drawdown and inleakage testing performed for the combined zone system alignment shall be considered adequate to demonstrate integrity of the combined zones.

Inservice hydrostatic testing and inservice leak pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code are performed prior to the reactor going critical after a refueling outage. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.6, Reactor Coolant System Pressure/Temperature Limits. These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence. With increased reactor fluence over time, the minimum allowable vessel temperature increases at a given pressure.

3/4.11 RADIOACTIVE EFFLUENTS

BASES

3/4.11.1.1 and 3/4.11.1.2 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

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RADIOACTIVE EFFLUENTS

BASES

3/4.11.1.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.11.1.4 LIQUID HOLDUP TANKS

The tanks listed in this specification include all those outdoor radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than 10 times the limits of 10 CFR Part 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

3/4.11.2.1 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

RADIOACTIVE EFFLUENTS

BASES

3/4 11.2.2 through 3/4 11.2.4 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

RADIOACTIVE EFFLUENTS

BASES

3/4.11.2.5 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

BASES

3/4.11.2.6 MAIN CONDENSER

Restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50.

3/4.11.2.7, 3/4.11.3, and 3/4.11.4 (Deleted) - INFORMATION FROM THESE SECTIONS RELOCATED TO THE ODCM OR PCP.

3/4.12 RADIOLOGICAL ENVIRONMENTAL MONITORING

BASES

Section 3/4.12 (Deleted)

THE INFORMATION FROM THIS SECTION
HAS BEEN RELOCATED TO THE ODCM.
BASES PAGE B 3/4 12-2 HAS BEEN
INTENTIONALLY OMITTED.

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BASES
FOR
SECTION 2.0
SAFETY LIMITS
AND
LIMITING SAFETY SYSTEM SETTINGS

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NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Section 2.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

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2.1 SAFETY LIMITS

BASES

2.0 INTRODUCTION

The fuel cladding, reactor pressure vessel and primary system piping are the principal barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The Technical Specification Safety Limit is set generically on a fuel product Minimum Critical Power Ratio (MCPR) correlation basis as the MCPR which corresponds to a 95% probability at a 95% confidence level that transition boiling will not occur, referred to as SLMCPR(95/95). The fuel cladding integrity Safety Limit is set such that no significant fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is not less than the limit specified in Specification 2.1.2. MCPR greater than the specified limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding Safety Limit is defined with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. These conditions represent a significant departure from the condition intended by design for planned operation. This is accomplished by having a Safety Limit Minimum Critical Power Ratio (SLMCPR) design basis, referred to as SLMCPR(95/95), which corresponds to a 95% probability at a 95% confidence level (the 95/95 MCPR criterion) that transition boiling will not occur.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

The use of the (GEXL) correlation is not valid for all critical power calculations at pressures below 700 psia for GNF2 [Ref. 2] and 600 psia for GNF3 [Ref. 3] or core flows less than 10% of rated flow. Therefore, the fuel cladding integrity Safety Limit is established by other means. This is done by establishing a limiting condition on core THERMAL POWER with the following basis. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be greater than 4.5 psi. Analyses show that with a bundle flow of 28×10^3 lb/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be greater than 28×10^3 lb/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER of more than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 25% of RATED THERMAL POWER for reactor pressure below 700 psia is conservative.

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SAFETY LIMITS

BASES

2.1.2 THERMAL POWER, High Pressure and High Flow

The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Since the parameters which result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions resulting in a departure from nucleate boiling have been used to mark the beginning of the region where fuel damage could occur. Although it is recognized that a departure from nucleate boiling would not necessarily result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. The Technical Specification Safety Limit value is dependent on the fuel product line and the corresponding MCPR correlation, which is cycle independent.

The value is based on the Critical Power Ratio (CPR) data statistics and a 95% probability with 95% confidence that rods are not susceptible to boiling transition, referred to as MCPR(95/95).

The Safety Limit is based on GNF2 and/or GNF3 fuel. For cores with a single fuel product line, the SLMCPR(95/95) is the MCPR(95/95) for the fuel type. For cores loaded with a mix of applicable fuel types, the SLMCPR(95/95) is based on the largest (i.e., most limiting) of the MCPR values for the fuel product lines that are fresh or once-burnt at the start of the cycle.

Reference:

1. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).
2. "GEXL17 Correlation for GNF2 Fuel," NEDC-33292P Rev. 3, April 2009
3. "GEXL21 Correlation for GNF3 Fuel," NEDC-33880P Rev. 1, November 2017

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SAFETY LIMITSBASES

2.1.3 REACTOR COOLANT SYSTEM PRESSURE

The Safety Limit for the reactor coolant system pressure has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to Section III of the ASME Boiler and Pressure Vessel Code 1968 Edition, including Addenda through Summer 1969, which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The Safety Limit of 1325 psig, as measured by the reactor vessel steam dome pressure indicator, is equivalent to 1375 psig at the lowest elevation of the reactor coolant system. The reactor coolant system is designed to the ASME Boiler and Pressure Vessel Code, 1977 Edition, including Addenda through Summer 1977 for the reactor recirculation piping, which permits a maximum pressure transient of 110%, 1375 psig of design pressure, 1250 psig for suction piping and 1500 psig for discharge piping. The pressure Safety Limit is selected to be the lowest transient overpressure allowed by the ASME Boiler and Pressure Vessel Code Section III, Class I.

2.1.4 REACTOR VESSEL WATER LEVEL

With fuel in the reactor vessel during periods when the reactor is shutdown, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level became less than two-thirds of the core height. The Safety Limit has been established at the top of the active irradiated fuel to provide a point which can be monitored and also provide adequate margin for effective action.

2.2 LIMITING SAFETY SYSTEM SETTINGS

BASES

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each parameter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. All four voters will trip (full scram) when any two unbypassed APRM channels exceed their trip setpoints.

APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels.

For operation at low pressure and low flow during STARTUP, the APRM Neutron Flux-Upscale (Setdown) scram setting of 15% of RATED THERMAL POWER provides adequate thermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

LIMITING SAFETY SYSTEM SETTINGS

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The 15% Neutron Flux - Upscale (Setdown) trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Neutron Flux - Upscale setpoint; i.e., for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Simulated Thermal Power - Upscale setpoint, a time constant of 6 ± 0.6 seconds is introduced into the flow-biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow-biased setpoint as shown in Table 2.2.1-1.

A reduced Trip Setpoint and Allowable Value is provided for the Simulated Thermal Power - Upscale Function, applicable when the plant is operating in Single Loop Operation (SLO) per LCO 3.4.1.1. In SLO, the drive flow values (W) used in the Trip Setpoint and Allowable Value equations is reduced by 7.6%. The 7.6% value is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. The Trip Setpoint and Allowable Value thus maintain thermal margins essentially unchanged from those for two-loop operation. The Trip Setpoint and Allowable Value equations for single loop operation are only valid for flows down to $W = 7.6\%$. The Trip Setpoint and Allowable Value do not go below 61.5% and 62.0% RATED THERMAL POWER, respectively. This is acceptable because back flow in the inactive recirculation loop is only an issue with drive flows of approximately 40% or greater (Reference 1).

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unnecessary shutdown.

The APRM channels also include an Oscillation Power Range Monitor (OPRM) Upscale Function. The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR Safety Limit due to anticipated thermal-hydraulic power oscillations. The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into "cells" for evaluation by the OPRM algorithms.

References 2, 3 and 4 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

LIMITING SAFETY SYSTEM SETTINGS

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is $\geq 29.5\%$ and recirculation drive flow is $< 60\%$ as indicated by APRM measured recirculation drive flow. (NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. Refer to TS Bases 3/4.3.1 for further discussion concerning the recirculation drive flow/core flow relationship.) This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. See Reference 5 for additional discussion of OPRM Upscale trip enable region limits. These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Upscale trip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in a cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect oscillatory changes in the neutron flux for one or more cells in that channel.

There are four "sets" of OPRM related setpoints or adjustment parameters: a) OPRM trip auto-enable setpoints for APRM Simulated Thermal Power (29.5%) and recirculation drive flow (60%); b) period based detection algorithm (PBDA) confirmation count and amplitude setpoints; c) period based detection algorithm tuning parameters; and d) growth rate algorithm (GRA) and amplitude based algorithm (ABA) setpoints.

The first set, the OPRM auto-enable region setpoints, are treated as nominal setpoints with no additional margins added as discussed in Reference 5. The settings, 29.5% APRM Simulated Thermal Power and 60% recirculation drive flow, are defined (limit values) in a note to Table 2.2.1-1. The second set, the OPRM PBDA trip setpoints, are established in accordance with methodologies defined in Reference 4, and are documented in the COLR. There are no allowable values for these setpoints. The third set, the OPRM PBDA "tuning" parameters, are established or adjusted in accordance with and controlled by station procedures. The fourth set, the GRA and ABA setpoints, in accordance with References 2 and 3, are established as nominal values only, and controlled by station procedures.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine stop valve and control fast closure trips are bypassed. For a turbine trip or load rejection under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

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LIMITING SAFETY SYSTEM SETTINGS

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint has been used in transient analyses dealing with coolant inventory decrease. The scram setting was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel and pressure limits.

5. Main Steam Line Isolation Valve-Closure

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIVs closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

6. DELETED

7. Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems or a loss of drywell cooling. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant and to the primary containment. The trip setting was selected as low as possible without causing spurious trips.

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LIMITING SAFETY SYSTEM SETTING

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REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

8. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of 25.45 gallons of water.

9. Turbine Stop Valve-Closure

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst design basis transient.

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

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the Reactor Protection System. This trip setting, a faster closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

11. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position is a redundant channel to the automatic protective instrumentation channels and provides additional manual reactor trip capability.

12. Manual Scram

The Manual Scram is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

LIMITING SAFETY SYSTEM SETTINGS

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

REFERENCES:

1. NEDC-31300, "Single-Loop Operation Analysis for Limerick Generating Station, Unit 1," August 1986.
2. NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.
3. NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.
4. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.
5. BWROG Letter 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), "Guidelines for Stability Option III 'Enable Region' (TAC M92882)," September 17, 1996.

BASES FOR
SECTIONS 3.0 AND 4.0
LIMITING CONDITIONS FOR OPERATION
AND
SURVEILLANCE REQUIREMENTS

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NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Sections 3.0 and 4.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

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3/4.0 APPLICABILITY

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Specifications 3.0.1 through 3.0.9 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

"Limiting Conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL CONDITIONS or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met. The ACTIONS for not meeting a single LCO adequately manage any increase in plant risk, provided any unusual external conditions (e.g., severe weather, offsite power instability) are considered. In addition, the increased risk associated with simultaneous removal of multiple structures, systems, trains or components from service is assessed and managed in accordance with 10 CFR 50.65(a)(4).

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in an OPERATIONAL CONDITION or other specified condition in which the specification no longer applies.

The specified time limits of the ACTION requirements are applicable from the point of time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered an OPERATIONAL CONDITION in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

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Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval, unless otherwise specified. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown CONDITION when plant operation cannot be maintained within the limits for safe operation defined by the Limiting Conditions for Operation and its ACTION requirements. Planned entry into LCO 3.0.3 should be avoided. If it is not practicable to avoid planned entry into LCO 3.0.3, plant risk should be assessed and managed in accordance with 10 CFR 50.65(a)(4), and the planned entry into LCO 3.0.3 should have less effect on plant safety than other practicable alternatives. One hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This time permits the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to enter lower CONDITIONS of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met, the ACTION is no longer applicable, or time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in COLD SHUTDOWN when a shutdown is required during POWER operation. If the plant is in a lower CONDITION of operation when a shutdown is required, the time limit for entering the next lower CONDITION of operation applies. However, if a lower CONDITION of operation is entered in less time than allowed, the total allowable time to enter COLD SHUTDOWN, or other OPERATIONAL CONDITION, is not reduced. For example, if STARTUP is entered in 2 hours, the time allowed to enter HOT SHUTDOWN is the next 11 hours because the total time to enter HOT SHUTDOWN is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to enter a lower CONDITION of operation in less than the total time allowed.

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The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into an OPERATIONAL CONDITION or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time limits of ACTION requirements for a higher CONDITION of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower CONDITION of operation.

The shutdown requirements of Specification 3.0.3 do not apply in CONDITIONS 4 and 5, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 establishes limitations on changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability when a Limiting Condition for Operation is not met. It allows placing the unit in an OPERATIONAL CONDITION or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the Limiting Condition for Operation would not be met, in accordance with either Specification 3.0.4.a, Specification 3.0.4.b, or Specification 3.0.4.c.

Specification 3.0.4.a allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met when the associated ACTION requirements to be entered following entry into the OPERATIONAL CONDITION or other specified condition in the Applicability will permit continued operation within the MODE or other specified condition for an unlimited period of time. Compliance with ACTIONS that permit continued operation of the unit for an unlimited period of time in an OPERATIONAL CONDITION or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the OPERATIONAL CONDITION change. Therefore, in such cases, entry into an OPERATIONAL CONDITION or other specified condition in the Applicability may be made and the Required Actions followed after entry into the Applicability.

For example, LCO 3.0.4.a may be used when the Required Action to be entered states that an inoperable instrument channel must be placed in the trip condition within the Completion Time. Transition into a MODE or other specified condition in the Applicability may be made in accordance with LCO 3.0.4 and the channel is subsequently placed in the tripped condition within the Completion Time, which begins when the Applicability is entered. If the instrument channel cannot be placed in the tripped condition and the subsequent default ACTION ("Required Action and associated Completion Time not met") allows the OPERABLE train to be placed in operation, use of LCO 3.0.4.a is acceptable because the subsequent ACTIONS to be entered following entry into the MODE include ACTIONS (place the OPERABLE train in operation) that permit safe plant operation for an unlimited period of time in the MODE or other specified condition to be entered.

Specification 3.0.4.b allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

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The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities be assessed and managed. The risk assessment, for the purposes of Specification 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed OPERATIONAL CONDITION change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the Limiting Condition for Operation would be met prior to the expiration of the ACTION requirement's specified time interval that would require exiting the Applicability.

Specification 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and any corresponding risk management actions. The Specification 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in OPERATIONAL CONDITION 1 for the duration of the specified time interval. Since this is allowable, and since in general the risk impact in that particular OPERATIONAL CONDITION bounds the risk of transitioning into and through the applicable OPERATIONAL CONDITIONS or other specified conditions in the Applicability of the Limiting Condition for Operation, the use of the Specification 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the Specification 3.0.4.b allowance is prohibited. The Limiting Condition for Operations governing these system and components contain Notes prohibiting the use of Specification 3.0.4.b by stating that Specification 3.0.4.b is not applicable.

Specification 3.0.4.c allows entry into a OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met based on a Note in the Specification which states Specification 3.0.4.c is applicable. These specific allowances permit entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability when the associated ACTION requirements to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTION requirements or to a specific ACTION requirement of a Specification. The risk assessments performed to justify the use of Specification 3.0.4.b usually only consider systems and components. For this

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reason, Specification 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Reactor Coolant Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

The provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified

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conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Upon entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met, Specification 3.0.1 and Specification 3.0.2 require entry into the applicable Conditions and ACTION requirements until the Condition is resolved, until the Limiting Condition for Operation is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by Specification 4.0.1. Therefore, utilizing Specification 3.0.4 is not a violation of Specification 4.0.1 or Specification 4.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected Limiting Condition for Operation.

Specification 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to Specifications 3.0.1 and 3.0.2 (e.g., to not comply with the applicable ACTION(s)) to allow the performance of required testing to demonstrate:

- a. The OPERABILITY of the equipment being returned to service, or
- b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance. LCO 3.0.5 should not be used in lieu of other practicable alternatives that comply with Required Actions and that do not require changing the MODE or other specified conditions in the Applicability in order to demonstrate equipment is OPERABLE. LCO 3.0.5 is not intended to be used repeatedly.

An example of demonstrating equipment is OPERABLE with the Required Actions not met is opening a manual valve that was closed to comply with Required Actions to isolate a flowpath with excessive Reactor Coolant System (RCS) Pressure Isolation Valve (PIV) leakage in order to perform testing to demonstrate that RCS PIV leakage is now within limit.

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Examples of demonstrating equipment OPERABILITY include instances in which it is necessary to take an inoperable channel or trip system out of a tripped condition that was directed by a Required Action, if there is no Required Action Note for this purpose. An example of verifying OPERABILITY of equipment removed from service is taking a tripped channel out of the tripped condition to permit the logic to function and indicate the appropriate response during performance of required testing on the inoperable channel.

Examples of demonstrating the OPERABILITY of other equipment are taking an inoperable channel or trip system out of the tripped condition 1) to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system, or 2) to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

The administrative controls in LCO 3.0.5 apply in all cases to systems or components in Chapter 3 of the Technical Specifications, as long as the testing could not be conducted while complying with the Required Actions. This includes the realignment or repositioning of redundant or alternate equipment or trains previously manipulated to comply with ACTIONS, as well as equipment removed from service or declared inoperable to comply with ACTIONS.

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Specification 3.0.6 establishes an exception to Specifications 3.0.1 and 3.0.2 for supported systems that have a support system Limiting Condition for Operation specified in the Technical Specifications (TS). The exception to Specification 3.0.1 is provided because Specification 3.0.1 would require that the ACTIONS of the associated inoperable supported system Limiting Condition for Operation be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support system Limiting Condition for Operation's ACTIONS. These ACTIONS may include entering the supported system's ACTIONS or may specify other ACTIONS. The exception to Specification 3.0.2 is provided because Specification 3.0.2 would consider not entering into the ACTIONS for the supported system within the specified time intervals as a TS noncompliance.

When a support system is inoperable and there is a Limiting Condition for Operation specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' ACTIONS unless directed to do so by the support system's ACTIONS. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' Limiting Condition for Operations' ACTIONS are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's ACTIONS.

However, there are instances where a support system's ACTION may either direct a supported system to be declared inoperable or direct entry into ACTIONS for the supported system. This may occur immediately or after some specified delay to perform some other ACTION. Regardless of whether it is immediate or after some delay, when a support system's ACTION directs a supported system to be declared inoperable or directs entry into ACTIONS for a supported system, the applicable ACTIONS shall be entered in accordance with Specification 3.0.1.

Specification 6.17, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into Specification 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system ACTIONS. The SFDP implements the requirements of Specification 3.0.6.

The following examples use Figure B 3.0-1 to illustrate loss of safety function conditions that may result when a TS support system is inoperable. In this figure, the fifteen systems that comprise Train A are independent and redundant to the fifteen systems that comprise Train B. To correctly use the figure to illustrate the SFDP provisions for a cross train check, the figure establishes a relationship between support and supported systems as follows: the figure shows System 1 as a support system for System 2 and System 3; System 2 as a support system for System 4 and System 5; and System 4 as a support system for System 8 and System 9. Specifically, a loss of safety function may exist when a support system is inoperable and:

- a. A system redundant to system(s) supported by the inoperable support system is also inoperable (EXAMPLE B 3.0.6-1),

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- b. A system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B 3.0.6-2), or
- c. A system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B 3.0.6-3).

For the following examples, refer to Figure B 3.0-1.

EXAMPLE B 3.0.6-1

If System 2 of Train A is inoperable and System 5 of Train B is inoperable, a loss of safety function exists in Systems 5, 10, and 11.

EXAMPLE B 3.0.6-2

If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11.

EXAMPLE B 3.0.6-3

If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10 and 11.

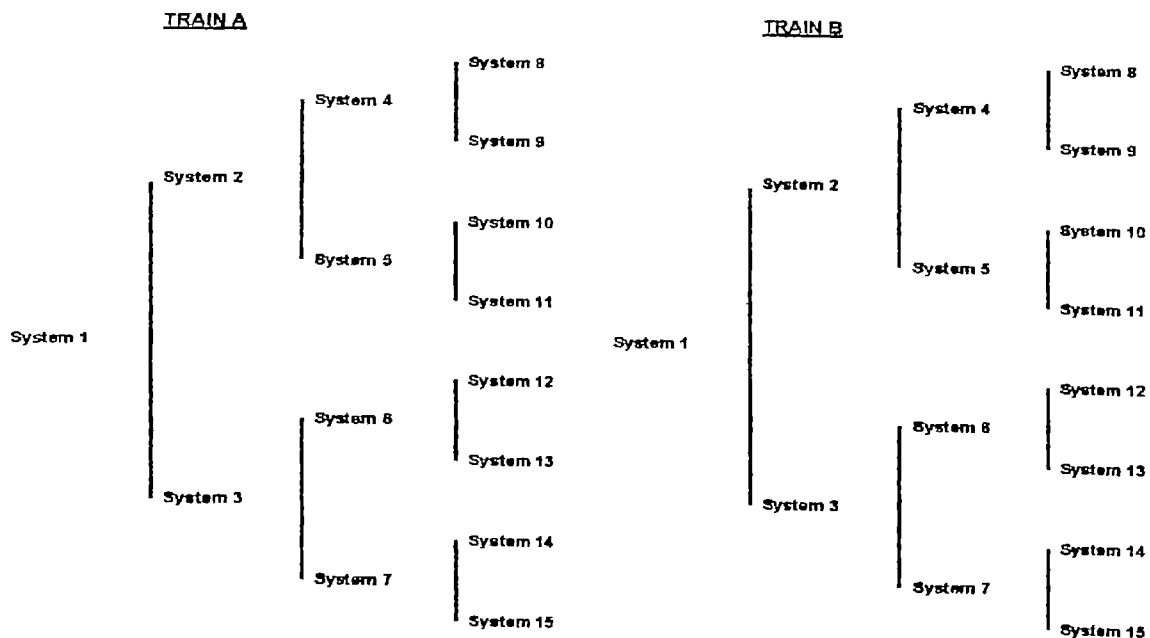


Figure B 3.0-1
Configuration of Trains and Systems

If an evaluation determines that a loss of safety function exists, the appropriate ACTIONS of the Limiting Condition for Operation in which the loss of safety function exists are required to be entered. This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account.

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When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate ACTIONS of the Limiting Condition for Operation in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level), the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the support system. The ACTIONS for a support system Limiting Condition for Operation adequately address the inoperabilities of that system without reliance on entering its supported system Limiting Condition for Operation. When the loss of function is the result of multiple support systems, the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the supported system.

Specification 3.0.7 - Not Used

Specification 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This Specification states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's Limiting Condition for Operation must be declared not met and the associated ACTION requirements shall be met in accordance with Specification 3.0.1.

Specification 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. Specification 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72-hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function and due to the availability of the redundant train of the supported system.

Specification 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. Specification 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12-hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

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The following configuration restrictions shall be applied to the use of Specification 3.0.8:

- (1) Specification 3.0.8.a can only be used if one of the following two means of heat removal is available:
 - a. At least one high pressure makeup path (e.g., using High Pressure Coolant Injection (HPCI) or Reactor Core Isolation Cooling (RCIC) or its equivalent) and heat removal capability (e.g., suppression pool cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s), or
 - b. At least one low pressure makeup path (e.g., Low Pressure Coolant Injection (LPCI) or Core Spray (CS)) and heat removal capability (e.g., suppression pool cooling or shutdown cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s).
- (2) Specification 3.0.8.b can only be used following verification that at least one success path exists, using equipment not associated with the inoperable snubber(s), to provide makeup and core cooling needed to mitigate Loss of Offsite Power (LOOP) accident sequences (i.e., initiated by a seismically-induced LOOP event with concurrent loss of all safety system trains supported by the out-of-service snubbers).

Specification 3.0.8 only applies to the seismic function of snubbers; it does not apply to the non-seismic functions of snubbers. Therefore, each use of Specification 3.0.8 for seismic snubbers that also have non-seismic functions requires confirmation that at least one train (or subsystem) of systems supported by the inoperable snubbers would remain capable of performing their required safety or support functions for postulated design loads other than seismic loads. In addition, a record of the design function of the inoperable snubber (i.e., seismic vs. non-seismic), implementation and compliance with the configuration restrictions defined above, and the associated plant configuration shall be available on a recoverable basis for NRC inspection.

Specification 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (i.e., the Maintenance Rule) does not address seismic risk. However, use of Specification 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

Specification 3.0.9 establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support function(s).

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This Limiting Condition for Operation states that the supported system is not considered to be inoperable

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solely due to required barriers not capable of performing their related support function(s) under the described conditions. Limiting Condition for Operation 3.0.9 allows 30 days before declaring the supported system(s) inoperable and the Limiting Conditions for Operation associated with the supported system(s) not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment.

If the allowed time expires and the barriers are unable to perform their related support function(s), the supported system's Limiting Conditions for Operation must be declared not met and the Conditions and Required Actions entered in accordance with Limiting Condition for Operation 3.0.2.

This provision does not apply to barriers which support ventilation systems or to fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs. This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2, 2001).

The provisions of Limiting Condition for Operation 3.0.9 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories:

- Loss of coolant accidents;
- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado or high wind.

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65 (a)(4), and the associated implementation guidance, Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that barriers are unable to perform their related support function(s).

Limiting Condition for Operation 3.0.9 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one train or subsystem of a multiple train or subsystem supported system, the barriers supporting each of these trains or subsystems must provide their related support function(s) for different categories of initiating events. For example, Limiting Condition for Operation 3.0.9 may be applied for up to 30 days for more than one train of a multiple train supported system if the affected barrier for one train protects against internal flooding and the affected barrier for the other train protects against tornado missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each train.

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The HPCI and RCIC systems are single train systems for injecting makeup water into the reactor during an accident or transient event. For the purposes of Limiting Condition for Operation 3.0.9, the HPCI system, the RCIC system, and the ADS are considered independent subsystems of a single system and Limiting Condition for Operation 3.0.9 can be used on these single train systems in a manner similar to multiple train or subsystem systems.

If during the time that Limiting Condition for Operation 3.0.9 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated Limiting Conditions for Operation declared not met. This 24 hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into Limiting Condition for Operation 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

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Specification 4.0.1 through 4.0.5 establish the general requirements applicable to Surveillance Requirements. SR 4.0.2 and SR 4.0.3 apply in Section 6, Administrative Controls, only when invoked by a Section 6 Specification. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations 10 CFR 50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration, or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

Specification 4.0.1 establishes the requirement that SRs must be met during the OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which the requirements of the Limiting Condition for Operation apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Surveillance time interval and allowed extension, in accordance with Specification 4.0.2, constitutes a failure to meet the Limiting Condition for Operation.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

- a. The systems or components are known to be inoperable, although still meeting the SRs; or
- b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in an OPERATIONAL CONDITION or other specified condition for which the requirements of the associated Limiting Condition for Operation are not applicable, unless otherwise specified. The SRs associated with a Special Test Exception Limiting Condition for Operation are only applicable when the Special Test Exception Limiting Condition for Operation is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given OPERATIONAL CONDITION or other specified condition.

Surveillances, including Surveillances invoked by ACTION requirements, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with Specification 4.0.2, prior to returning equipment to OPERABLE status.

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Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current OPERATIONAL CONDITION or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to an OPERATIONAL CONDITION or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

- a. Control Rod Drive maintenance during refueling that requires scram testing at > 950 psi. However, if other appropriate testing is satisfactorily completed and the scram time testing of Specification 4.1.3.2 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 950 psi to perform other necessary testing.
- b. High pressure coolant injection (HPCI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPCI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

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Specification 4.0.2 establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 24-month surveillance interval. It is not intended that this provision be used repeatedly to extend the surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. Likewise, it is not the intent that REFUELING INTERVAL surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been performed within the specified Surveillance time interval and allowed extension. A delay period of up to 24 hours or up to the limit of the specified Surveillance time interval, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with Specification 4.0.2, and not at the time that the specified Surveillance time interval and allowed extension was not met.

When a Section 6.8, "Procedures and Programs," specification states that the provisions of SR 4.0.3 are applicable, it permits the flexibility to defer declaring the testing requirement not met in accordance with SR 4.0.3 when the testing has not been completed within the testing interval (including the allowance of SR 4.0.2 if invoked by the Section 6.8 specification).

This delay period provides adequate time to perform Surveillances that have been missed. This delay period permits the performance of a Surveillance before complying with ACTION requirements or other remedial measures that might preclude performance of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Surveillance time interval based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering OPERATIONAL CONDITION 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to have not been performed when specified, Specification 4.0.3 allows for the full delay period of up to the specified Surveillance time interval to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

Specification 4.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of OPERATIONAL CONDITION changes imposed by ACTION requirements.

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Specification 4.0.3 (Continued)

SR 4.0.3 is only applicable if there is a reasonable expectation the associated equipment is OPERABLE or that variables are within limits, and it is expected that the Surveillance will be met when performed. Many factors should be considered, such as the period of time since the Surveillance was last performed, or whether the Surveillance, or a portion thereof, has ever been performed, and any other indications, tests, or activities that might support the expectation that the Surveillance will be met when performed. An example of the use of SR 4.0.3 would be a relay contact that was not tested as required in accordance with a particular SR, but previous successful performances of the SR included the relay contact; the adjacent, physically connected relay contacts were tested during the SR performance; the subject relay contact has been tested by another SR; or historical operation of the subject relay contact has been successful. It is not sufficient to infer the behavior of the associated equipment from the performance of similar equipment. The rigor of determining whether there is a reasonable expectation a Surveillance will be met when performed should increase based on the length of time since the last performance of the Surveillance. If the Surveillance has been performed recently, a review of the Surveillance history and equipment performance may be sufficient to support a reasonable expectation that the Surveillance will be met when performed. For Surveillances that have not been performed for a long period or that have never been performed, a rigorous evaluation based on objective evidence should provide a high degree of confidence that the equipment is OPERABLE. The evaluation should be documented in sufficient detail to allow a knowledgeable individual to understand the basis for the determination.

Failure to comply with specified Surveillance time intervals and allowed extensions for SRs is expected to be an infrequent occurrence. Use of the delay period established by Specification 4.0.3 is a flexibility which is not intended to be used repeatedly to extend Surveillance intervals.

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While up to 24 hours or the limit of the specified Surveillance time interval is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the Corrective Action Program.

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

Completion of the Surveillance within the delay period allowed by this Specification, or within the allowed times specified in the ACTION requirements, restores compliance with Specification 4.0.1.

Specification 4.0.4 establishes the requirement that all applicable SRs must be met before entry into an OPERATIONAL CONDITION or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

A provision is included to allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability when a Limiting Condition for Operation is not met due to a Surveillance not being met in accordance with Specification 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in Specification 4.0.4 restricting an OPERATIONAL CONDITION change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated

3/4.0 APPLICABILITY

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SR(s) are not required to be performed, per Specification 4.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, Specification 4.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Surveillance time interval does not result in a Specification 4.0.4 restriction to changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability. However, since the Limiting Condition for Operation is not met in this instance, Specification 3.0.4 will govern any restrictions that may (or may not) apply to OPERATIONAL CONDITION or other specified condition changes. Specification 4.0.4 does not restrict changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Surveillance time interval, provided the requirement to declare the Limiting Condition for Operation not met has been delayed in accordance with Specification 4.0.3.

The provisions of Specification 4.0.4 shall not prevent entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 4.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Specification 4.0.5 establishes the requirement that 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 a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda, and the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as required by 10 CFR 50.55a. The provisions of SR 4.0.2 and SR 4.0.3 do not apply to the INSERVICE TESTING PROGRAM unless there is a specific SR referencing usage of the program.

Limerick Generating Station has received a license amendment to implement 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," and may voluntarily comply with the requirements of 10 CFR 50.69 as an alternative to compliance with the following requirements for structures, systems, and components (SSCs) that have a Risk-Informed Safety Class (RISC) of RISC-3:

- (1) The INSERVICE TESTING PROGRAM requirements of 10 CFR 50.55a(f), and
- (2) The inservice inspection, and repair and replacement (with the exception of fracture toughness), requirements for ASME Class 2 and Class 3 SSCs in 10 CFR 50.55a(g).

Therefore, SSCs that have been categorized as RISC-3 in accordance with 10 CFR 50.69 may be removed from the INSERVICE TESTING [IST] PROGRAM and the Inservice Inspection (ISI) Program in accordance with 10 CFR 50.69(b)(1)(v).

RISC-3 SSCs with technical specification surveillance requirements referencing Technical Specification 4.0.5, which have been removed from the IST/ISI programs, are subject to the alternative treatment requirements of 10 CFR 50.69(d)(2). The SSCs must continue to meet the acceptance criteria specified in associated technical specification surveillance requirements, as applicable; however, the surveillance frequency is determined as part of the alternative treatment.

3/4.1 REACTIVITY CONTROL SYSTEMS

BASES

3/4.1.1 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that (1) the reactor can be made subcritical from all operating conditions, (2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and (3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

Since core reactivity values will vary through core life as a function of fuel depletion and poison burnup, the demonstration of SHUTDOWN MARGIN will be performed in the cold, xenon-free condition and shall show the core to be subcritical by at least $R + 0.38\% \Delta k/k$ or $R + 0.28\% \Delta k/k$, as appropriate. The $0.38\% \Delta k/k$ includes uncertainties and calculation biases. The value of R in units of $\% \Delta k/k$ is the difference between the calculated value of minimum shutdown margin during the operating cycle and the calculated shutdown margin at the time of the shutdown margin test at the beginning of cycle. The value of R must be positive or zero and must be determined for each fuel loading cycle.

Two different values are supplied in the Limiting Condition for Operation to provide for the different methods of demonstration of the SHUTDOWN MARGIN. The highest worth rod may be determined analytically or by test. The SHUTDOWN MARGIN is demonstrated by (an insequence) control rod withdrawal at the beginning of life fuel cycle conditions, and, if necessary, at any future time in the cycle if the first demonstration indicates that the required margin could be reduced as a function of exposure. Observation of subcriticality in this condition assures subcriticality with the most reactive control rod fully withdrawn.

This reactivity characteristic has been a basic assumption in the analysis of plant performance and can be best demonstrated at the time of fuel loading, but the margin must also be determined anytime a control rod is incapable of insertion.

3/4.1.2 REACTIVITY ANOMALIES

Since the SHUTDOWN MARGIN requirement for the reactor is small, a careful check on actual conditions to the predicted conditions is necessary, and the changes in reactivity can be inferred from these comparisons of core $k_{\text{effective}}$ (k_{eff}). Since the comparisons are easily done, frequent checks are not an imposition on normal operations. A 1% change is larger than is expected for normal operation so a change of this magnitude should be thoroughly evaluated. A change as large as 1% would not exceed the design conditions of the reactor and is on the safe side of the postulated transients.

REACTIVITY CONTROL SYSTEMS

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3/4.1.3 CONTROL RODS

The specification of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the accident analysis, and (3) the potential effects of the rod drop accident are limited. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

Damage within the control rod drive mechanism could be a generic problem, therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than the fuel cladding safety limit during the limiting power transient analyzed in Section 15.2 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provided the required protection and MCPR remains greater than the fuel cladding safety limit. The occurrence of scram times longer than those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

Scram time testing at zero psig reactor coolant pressure is adequate to ensure that the control rod will perform its intended scram function during startup of the plant until scram time testing at 950 psig reactor coolant pressure is performed prior to exceeding 40% rated core thermal power.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

The OPERABILITY of all SDV vent and drain valves ensures that the SDV vent and drain valves will close during a scram to contain reactor water discharged to the SDV piping. The SDV has one common drain line and one common vent line. Since the vent and drain lines are provided with two valves in series, the single failure of one valve in

REACTIVITY CONTROL SYSTEMS

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CONTROL RODS (Continued)

the open position will not impair the isolation function of the system. Additionally, the valves are required to open on scram reset to ensure that a path is available for the SDV piping to drain freely at other times.

When one SDV vent or drain valve is inoperable in one or more lines, the valves must be restored to OPERABLE status within 7 days. The allowable outage time is reasonable, given the level of redundancy in the lines and the low probability of a scram occurring while the valve(s) are inoperable. The SDV is still isolable since the redundant valve in the affected line is OPERABLE. During these periods, the single failure criterion may not be preserved, and a higher risk exists to allow reactor water out of the primary system during a scram.

If both valves in a line are inoperable, the line must be isolated to contain the reactor coolant during a scram. When a line is isolated, the potential for an inadvertent scram due to high SDV level is increased. ACTION "e" is modified by a note ("****") that allows periodic draining and venting of the SDV when a line is isolated. During these periods, the line may be unisolated under administrative control. This allows any accumulated water in the line to be drained, to preclude a reactor scram on SDV high level. This is acceptable since the administrative controls ensure the valve can be closed quickly, by a dedicated operator, if a scram occurs with the valve open. The 8 hour allowable outage time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and the unlikelihood of significant CRD seal leakage.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. The drive water pressure normal operating range is specified in system operating procedures which provide ranges for system alignment and control rod motion (exercising). Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactor. A control rod is considered trippable if it is capable of fully inserting as a result of a scram signal.

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CONTROL RODS (Continued)

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The required surveillances are adequate to determine that the rods are OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in a peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 10% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RWM to be OPERABLE when THERMAL POWER is less than or equal to 10% of RATED THERMAL POWER provides adequate control.

The RWM provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4.9 of the FSAR and the techniques of the analysis are presented in a topical report, Reference 1, and two supplements, References 2 and 3. Additional pertinent analysis is also contained in Amendment 17 to the Reference 4 topical report.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density over the range of power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods. RBM OPERABILITY is required when the limiting condition described in Specification 3.1.4.3 exists.

REACTIVITY CONTROL SYSTEMS

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3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

The standby liquid control system provides a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown, assuming that the withdrawn control rods remain fixed in the rated power pattern. To meet this objective it is necessary to inject a quantity of boron which produces a concentration of 660 ppm in the reactor core and other piping systems connected to the reactor vessel. To allow for potential leakage and improper mixing, this concentration is increased by 25%. The required concentration is achieved by having available a minimum quantity of 3,160 gallons of sodium pentaborate solution containing a minimum of 3,754 lbs of sodium pentaborate having the requisite Boron-10 atom % enrichment of 29% as determined from Reference 5. This quantity of solution is a net amount which is above the pump suction shutoff level setpoint thus allowing for the portion which cannot be injected.

The above quantities calculated at 29% Boron-10 enrichment have been demonstrated by analysis to provide a Boron-10 weight equivalent of 185 lbs in the sodium pentaborate solution. Maintaining this Boron-10 weight in the net tank contents ensures a sufficient quantity of boron to bring the reactor to a cold, Xenon-free shutdown.

The pumping rate of 37.0 gpm provides a negative reactivity insertion rate over the permissible solution volume range, which adequately compensates for the positive reactivity effects due to elimination of steam voids, increased water density from hot to cold, reduced doppler effect in uranium, reduced neutron leakage from boiling to cold, decreased control rod worth as the moderator cools, and xenon decay. The temperature requirement ensures that the sodium pentaborate always remains in solution.

With redundant pumps and explosive injection valves and with a highly reliable control rod scram system, operation of the reactor is permitted to continue for short periods of time with the system inoperable or for longer periods of time with one of the redundant components inoperable.

The SLCS system consists of three separate and independent pumps and explosive valves. Two of the separate and independent pumps and explosive valves are required to meet the minimum requirements of this technical specification and, where applicable, satisfy the single failure criterion. To ensure that SLCS pump discharge pressure does not exceed the SLCS relief valve setpoint during operation following an anticipated transient without scram (ATWS) event, no more than two pumps shall be aligned for automatic operation in OPERATIONAL CONDITIONS 1, 2, and 3. This maintains the equivalent control capacity to satisfy 10 CFR 50.62 (Requirements for reduction of risk from anticipated transients without scram (ATWS)). With three pumps aligned for automatic operation, the system is inoperable and ACTION statement (b) applies.

The SLCS must have an equivalent control capacity of 86 gpm of 13% weight sodium pentaborate in order to satisfy 10 CFR 50.62. As part of the ARTS/MELLL program the ATWS analysis was updated to reflect the new rod line. As a result of this it was determined that the Boron 10 enrichment was required to be increased to 29% to prevent exceeding a suppression pool temperature of 190°F. This equivalency requirement is fulfilled by having a system which satisfies the equation given in 4.1.5.b.2.

The upper limit concentration of 13.8% has been established as a reasonable limit to prevent precipitation of sodium pentaborate in the event of a loss of tank heating, which allow the solution to cool. A SLCS Pump flowrate of 37.0 gpm (minimum) and a Sodium Pentaborate Solution concentration of 9% by weight (minimum) will require a Boron-10 enrichment of 49 atom % to be added to the tank. The decreased pump flowrate and increased solution enrichment are acceptable because the results of the ATWS Rule Equation will remain > 1.0 .

REACTIVITY CONTROL SYSTEMS

BASES

STANDBY LIQUID CONTROL SYSTEM (Continued)

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume assures that the solution is available for use.

Replacement of the explosive charges in the valves will assure that these valves will not fail because of deterioration of the charges.

The Standby Liquid Control System also has a post-DBA LOCA safety function to buffer Suppression Pool pH in order to maintain bulk pH above 7.0. The buffering of Suppression Pool pH is necessary to prevent iodine re-evolution to satisfy the methodology for Alternative Source Term. Manual initiation is used, and the minimum amount of total boron required for Suppression Pool pH buffering is 256 lbs. Given that at least 185 lbs of Boron-10 is maintained in the tank, the total boron in the tank will be greater than 256 lbs for the range of enrichments from 29% to 62%.

ACTION Statement (a) applies only to OPERATIONAL CONDITIONS 1 and 2 because a single pump can satisfy both the reactor control function and the post-DBA LOCA function to control Suppression Pool pH since boron injection is not required until 13 hours post-LOCA. ACTION Statement (b) applies to OPERATIONAL CONDITIONS 1, 2 and 3 to address the post-LOCA safety function of the SLC system.

1. C. J. Paone, R. C. Stirn and J. A. Woolley, "Rod Drop Accident Analysis for Large BWR's," G. E. Topical Report NEDO-10527, March 1972.
2. C. J. Paone, R. C. Stirn, and R. M. Young, Supplement 1 to NEDO-10527, July 1972.
3. J. M. Haun, C. J. Paone, and R. C. Stirn, Addendum 2, "Exposed Cores," Supplement 2 to NEDO-10527, January 1973.
4. Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel."
5. "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," NEDC-32193P, Revision 2, October 1993.

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3/4.2 POWER DISTRIBUTION LIMITS

BASES

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

This specification assures that the peak cladding temperature (PCT) following the postulated design basis Loss-of-Coolant Accident (LOCA) will not exceed the limits specified in 10 CFR 50.46 and that the fuel design analysis limits specified in NEDE-24011-P-A (Reference 2) will not be exceeded.

Mechanical Design Analysis: NRC approved methods (specified in Reference 2) are used to demonstrate that all fuel rods in a lattice operating at the bounding power history, meet the fuel design limits specified in Reference 2. No single fuel rod follows, or is capable of following, this bounding power history. This bounding power history is used as the basis for the fuel design analysis MAPLHGR limit.

LOCA Analysis: A LOCA analysis is performed in accordance with 10 CFR 50 Appendix K to demonstrate that the permissible planar power (MAPLHGR) limits comply with the ECCS limits specified in 10 CFR 50.46. The analysis is performed for the most limiting break size, break location, and single failure combination for the plant, using the evaluation model described in Reference 9.

The MAPLHGR limit as shown in the CORE OPERATING LIMITS REPORT is the most limiting composite of the fuel mechanical design analysis MAPLHGR and the ECCS MAPLHGR limit.

Only the most limiting MAPLHGR values are shown in the CORE OPERATING LIMITS REPORT for multiple lattice fuel. Compliance with the specific lattice MAPLHGR operating limits, which are available in Reference 3, is ensured by use of the process computer.

As a result of no longer utilizing an APRM trip setdown requirement, additional constraints are placed on the MAPLHGR limits to assure adherence to the fuel-mechanical design bases. These constraints are introduced through the MAPFAC(P) and MAPFAC(F) factors as defined in the COLR.

POWER DISTRIBUTION LIMITS

BASES

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POWER DISTRIBUTION LIMITS

BASES

3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady-state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity MCPR(99.9%), and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady-state operating limit, it is required that less than 0.1% of fuel rods in the core are susceptible to transition boiling or that the resulting MCPR does not decrease below the operating limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0-2 that are input to a BWR system dynamic behavior transient computer program. The codes used to evaluate transients are discussed in Reference 2.

MCPR(99.9%) is determined to ensure more than 99.9% of the fuel rods in the core are not susceptible to boiling transition using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved Critical Power correlations. Details of the MCPR(99.9%) calculation are given in Reference 2. Reference 2 also includes a tabulation of the uncertainties and the nominal values MCPR99.9% statistical analysis.

The MCPR operating limits are derived from the MCPR(99.9%) value and the transient analysis and are dependent on the operating core flow and power state (MCPR(F), and MCPR(P), respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Ref. 6). Flow dependent MCPR limits (MCPR(F)) are determined by steady state thermal hydraulic methods with key physics response inputs benchmarked using the three dimensional BWR simulator code (Ref. 7) to analyze slow flow runout transients.

Power dependent MCPR limits (MCPR(P)) are determined by approved transient analysis (Reference 2). Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scrams are bypassed, high and low flow MCPR(P), operating limits are provided for operating between 25% RTP and 30% RTP.

The MCPR operating limits specified in the COLR (MCPR(99.9%) value, MCPR(F), and MCPR(P) values) are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the MCPR(F), and MCPR(P) limits, which are based on the MCPR(99.9%) limit specified in the COLR.

POWER DISTRIBUTION LIMITS

BASES

MINIMUM CRITICAL POWER RATIO (Continued)

At THERMAL POWER levels less than or equal to 25% of RATED THERMAL POWER, the reactor will be operating at minimum recirculation pump speed and the moderator void content will be very small. For all designated control rod patterns which may be employed at this point, operating plant experience indicates that the resulting MCPR value is in excess of requirements by a considerable margin. During initial start-up testing of the plant, a MCPR evaluation will be made at 25% of RATED THERMAL POWER level with minimum recirculation pump speed. The MCPR margin will thus be demonstrated such that future MCPR evaluation below this power level will be shown to be unnecessary. The daily requirement for calculating MCPR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR when a limiting control rod pattern is approached ensures that MCPR will be known following a change in THERMAL POWER or power shape, regardless of magnitude, that could place operation at a thermal limit.

3/4.2.4 LINEAR HEAT GENERATION RATE

This specification assures that the Linear Heat Generation Rate (LHGR) in any rod is less than the design linear heat generation even if fuel pellet densification is postulated.

Reference:

1. Deleted.
2. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).
3. "Basis of MAPLHGR Technical Specifications for Limerick Unit 1," NEDO-31401, February 1987 (as amended).
4. Deleted
5. Increased Core Flow and Partial Feedwater Heating Analysis for Limerick Generating Station Unit 1 Cycle 1, NEDC-31323, October 1986 including Errata and Addenda Sheet No. 1 dated November 6, 1986.
6. NEDC-32193P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," Revision 2, October 1993.
7. NEDO-30130-A, "Steady State Nuclear Methods," May 1985.
8. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," October 1978.
9. NEDC-32170P, "Limerick Generating Station Units 1 and 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," June 1993.

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3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

- a. Preserve the integrity of the fuel cladding.
- b. Preserve the integrity of the reactor coolant system.
- c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and
- d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed.

The system meets the intent of IEEE-279 for nuclear power plant protection systems. Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System" and NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function." The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

The APRM Functions include five Functions accomplished by the four APRM channels (Functions 2.a, 2.b, 2.c, 2.d, and 2.f) and one accomplished by the four 2-Out-Of-4 Voter channels (Function 2.e). Two of the five Functions accomplished by the APRM channels are based on neutron flux only (Functions 2.a and 2.c), one Function is based on neutron flux and recirculation drive flow (Function 2.b) and one is based on equipment status (Function 2.d). The fifth Function accomplished by the APRM channels is the Oscillation Power Range Monitor (OPRM) Upscale trip Function 2.f, which is based on detecting oscillatory characteristics in the neutron flux. The OPRM Upscale Function is also dependent on average neutron flux (Simulated Thermal Power) and recirculation drive flow, which are used to automatically enable the output trip.

The Two-Out-Of-Four Logic Module includes 2-Out-Of-4 Voter hardware and the APRM Interface hardware. The 2-Out-Of-4 Voter Function 2.e votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. This voting is accomplished by the 2-Out-Of-4 Voter hardware in the Two-Out-Of-Four Logic Module. The voter includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The analysis in Reference 2 took credit for this redundancy in the justification of the 12-hour allowed out-of-service time for

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

Action b, so the voter Function 2.e must be declared inoperable if any of its functionality is inoperable. The voter Function 2.e does not need to be declared inoperable due to any failure affecting only the APRM Interface hardware portion of the Two-Out-Of-Four Logic Module.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. To provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. In addition, no more than 9 LPRMs may be bypassed between APRM calibrations (weekly gain adjustments). For the OPRM Upscale Function 2.f, LPRMs are assigned to "cells" of 3 or 4 detectors. A minimum of 23 cells (Reference 9), each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for each APRM channel for the OPRM Upscale Function 2.f to be OPERABLE in that channel. LPRM gain settings are determined from the local flux profiles measured by the TIP system. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 2000 EFPH frequency is based on operating experience with LPRM sensitivity changes.

References 4, 5 and 6 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in any cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux for one or more cells in that channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is at $\geq 25\%$ RATED THERMAL POWER. The 25% RATED THERMAL POWER level is selected to provide margin in the unlikely event that a reactor power increase transient occurring while the plant is operating below 29.5% RATED THERMAL POWER causes a power increase to or beyond the 29.5% RATED THERMAL POWER OPRM Upscale trip auto-enable point without operator action. This OPERABILITY requirement assures that the OPRM Upscale trip automatic-enable function will be OPERABLE when required.

Actions a, b and c define the Action(s) required when RPS channels are discovered to be inoperable. For those Actions, separate entry condition is allowed for each inoperable RPS channel. Separate entry means that the allowable time clock(s) for Actions a, b or c start upon discovery of inoperability for that specific channel. Restoration of an inoperable RPS channel satisfies only the action statements for that particular channel. Action statement(s) for remaining inoperable channel(s) must be met according to their original entry time.

A Note has been provided to modify the Actions when Functional Unit 2.b and 2.a channels are inoperable due to failure of SR 4.3.1.1 and gain adjustments are necessary. The Note allows entry into associated Actions to be delayed for up to 2 hours if the APRM is indicating a lower power value than the calculated power (i.e., the gain adjustment factor (GAF) is high (non-conservative)). The GAF for any channel is defined as the power value determined by the heat balance divided by the APRM reading for that channel. Upon completion of the gain adjustment, or

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

expiration of the allowed time, the channel must be returned to OPERABLE status or the applicable Actions taken. This Note is based on the time required to perform gain adjustments on multiple channels.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (NEDC-30851P-A and NEDC-32410P-A) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided that the associated Function's (identified as a "Functional Unit" in Table 3.3.1-1) inoperable channel is in one trip system and the Function still maintains RPS trip capability. Alternatively, an allowable out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

The requirements of Action a are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic, including the IRM Functions and APRM Function 2.e (trip capability associated with APRM Functions 2.a, 2.b, 2.c, 2.d, and 2.f are discussed below), this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip).

For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 9 (Turbine Stop Valve-Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The completion time to satisfy the requirements of Action a is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels. Alternatively, the completion time can be determined in accordance with the Risk Informed Completion Time Program.

With trip capability maintained, i.e., Action a satisfied, Actions b and c as applicable must still be satisfied. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Action b requires that the channel or the associated trip system must be placed in the tripped condition. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue.

As noted, placing the trip system in trip is not applicable to satisfy Action b for APRM functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, the Action b requirements can only be satisfied by placing the inoperable APRM channel in trip. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and the requirement to satisfy Action a.

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BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action c must be satisfied when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, normally the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system (see additional bases discussion above related to loss of trip capability and the requirements of Action a, and special cases for Functions 2.a, 2.b, 2.c, 2.d, 2.f, 5 and 9).

The requirements of Action c limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in NEDC-30851P-A for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function must have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing the actions required by Action c restores RPS to a reliability level equivalent to that evaluated in NEDC-30851P-A, which justified a 12 hour allowable out of service time as allowed by Action b. To satisfy the requirements of Action c, the trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what OPERATIONAL CONDITION the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

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

As noted, Action c is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-Out-Of-4 voter and other non-APRM channels for which Action c applies. For an inoperable APRM channel, the requirements of Action b can only be satisfied by tripping the inoperable APRM channel. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure.

If it is not desired to place the channel (or trip system) in trip to satisfy the requirements of Action a, Action b or Action c (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Action d requires that the Action defined by Table 3.3.1-1 for the applicable Function be initiated immediately upon expiration of the allowable out of service time.

Table 3.3.1-1, Function 2.f, references Action 10, which defines the action required if OPRM Upscale trip capability is not maintained. Action 10b is required to address identified equipment failures. Action 10a is to address common mode vendor/industry identified issues that render all four OPRM channels inoperable at once. For this condition, References 2 and 3 justified use of alternate methods to

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

detect and suppress oscillations for a limited period of time, up to 120 days. The alternate methods are procedurally established consistent with the guidelines identified in Reference 7 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed completion time to implement the alternate methods is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place. The 120-day period during which use of alternate methods is allowed is intended to be an outside limit to allow for the case where design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. The evaluation of the use of alternate methods concluded, based on engineering judgment, that the likelihood of an instability event that could not be adequately handled by the alternate methods during the 120-day period was negligibly small. Plant startup may continue while operating within the allowed completion time of Action 10a. The primary purpose of this is to allow an orderly completion, without undue impact on plant operation, of design and verification activities in the event of a required design change to the OPRM Upscale function. This exception is not intended as an alternative to restoring inoperable equipment to OPERABLE status in a timely manner.

Action 10a is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to be accomplished within the completion times allowed for LCO 3.3.1 Action a or Action b, as applicable. Action 10b applies when routine equipment OPERABILITY cannot be restored within the allowed completion times of LCO 3.3.1 Actions a or b, or if a common mode OPRM deficiency cannot be corrected and OPERABILITY of the OPRM Upscale Function restored within the 120-day allowed completion time of Action 10a.

The OPRM Upscale trip output shall be automatically enabled (not-bypassed) when APRM Simulated Thermal Power is $\geq 29.5\%$ and recirculation drive flow is $< 60\%$ as indicated by APRM measured recirculation drive flow. NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. As noted in Table 4.3.1.1-1, Note c, CHANNEL CALIBRATION for the OPRM Upscale trip Function 2.f includes confirming that the auto-enable (not-bypassed) setpoints are correct. Other surveillances ensure that the APRM Simulated Thermal Power properly correlates with THERMAL POWER (Table 4.3.1.1-1, Note d) and that recirculation drive flow properly correlates with core flow (Table 4.3.1.1-1, Note g).

If any OPRM Upscale trip auto-enable setpoint is exceeded and the OPRM Upscale trip is not enabled, i.e., the OPRM Upscale trip is bypassed when APRM Simulated Thermal Power is $\geq 29.5\%$ and recirculation drive flow is $< 60\%$, then the affected channel is considered inoperable for the OPRM Upscale Function. Alternatively, the OPRM Upscale trip auto-enable setpoint(s) may be adjusted to place the channel in the enabled condition (not-bypassed). If the OPRM Upscale trip is placed in the enabled condition, the surveillance requirement is met and the channel is considered OPERABLE.

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 4.3.1.1-1, Note g, CHANNEL CALIBRATION for the APRM Simulated Thermal Power - Upscale Function 2.b and the OPRM Upscale Function 2.f, includes the recirculation drive flow input function. The APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function both require a valid drive flow signal. The APRM Simulated Thermal Power - Upscale Function uses drive flow to vary the trip setpoint. The OPRM Upscale Function uses drive flow to automatically enable or bypass the OPRM Upscale trip output to RPS. A CHANNEL CALIBRATION of the APRM recirculation drive flow input function requires both calibrating the drive flow transmitters and establishing a valid drive flow / core flow relationship. The drive flow / core flow relationship is established once per refuel cycle, while operating within 10% of rated core flow and within 10% of RATED THERMAL POWER. Plant operational experience has shown that this flow correlation methodology is consistent with the guidance and intent in Reference 8. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function.

For the Simulated Thermal Power - Upscale Function (Function 2.b), the CHANNEL CALIBRATION surveillance requirement is modified by two Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the Trip Setpoint. The as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the Trip Setpoint, then the channel shall be declared inoperable. The as-left tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy and the measurement and test equipment error (including readability). The as-found tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy, instrument drift, and the measurement and test equipment error (including readability).

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to the reactor power calculated from a heat balance if the heat balance calculated reactor power exceeds the APRM channel output by more than 2% RTP.

This Surveillance does not preclude making APRM channel adjustments, if desired, when the heat balance calculated reactor power is less than the APRM channel output. To provide close agreement between the APRM indicated power and to preserve operating margin, the APRM channels are normally adjusted to within +/- 2% of the heat balance calculated reactor power. However, this agreement is not required for OPERABILITY when APRM output indicates a higher reactor power than the heat balance calculated reactor power.

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 3.3.1-2, Note "**", the redundant outputs from the 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8 to determine the interval between tests for application of Specification 4.3.1.3 (REACTOR PROTECTION SYSTEM RESPONSE TIME). The note further requires that testing of OPRM and APRM outputs shall be alternated.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-Out-Of-4 Voter channel for that function, and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. This testing frequency is twice the frequency justified by References 2 and 3.

Automatic reactor trip upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable except for the APRM Simulated Thermal Power - Upscale and Neutron Flux - Upscale trip functions and the OPRM Upscale trip function (Table 3.3.1-2, Items 2.b, 2.c, and 2.f). Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) in-place, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. Response time testing for the sensors as noted in Table 3.3.1-2 is not required based on the analysis in NEDO-32291-A. Response time testing for the remaining channel components is required as noted. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

INSTRUMENTATION

BASES

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 2, "Technical Specification Improvement Analysis for BWR Instrumentation Common to RPS and ECCS Instrumentation" as approved by the NRC and documented in the NRC Safety Evaluation Report (SER) (letter to D.N. Grace from C.E. Rossi dated January 6, 1989) and NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the NRC SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Automatic closure of the MSIVs upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

Response time testing for sensors are not required based on the analysis in NEDO 32291-A. Response time testing of the remaining channel components is required as noted in Table 3.3.2-3.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. Primary containment isolation valves that are actuated by the isolation signals specified in Technical Specification Table 3.3.2-1 are identified in Technical Requirements Manual Table 3.6.3-1.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.3.2 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

INSTRUMENTATION

BASES

3/4.3.3 EMERGENCY CORE COOLING ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.3.A REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation if they will be isolated by valves that will close

INSTRUMENTATION

BASES

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, "Reactor Pressure Vessel (RPV) Water Inventory Control (WIC)," and the definition of DRAIN TIME. There are functions that support automatic isolation of Residual Heat Removal (RHR) subsystem and Reactor Water Cleanup (RWCU) system penetration flow path(s) on low RPV water level.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure. It is assumed, based on engineering judgment, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Permissive and interlock setpoints are generally considered as nominal values without regard to measurement accuracy.

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

INSTRUMENTATION

BASES

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

RHR System Isolation - Reactor Vessel Water Level Low - Level 3

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level Low - Level 3 Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

Reactor Vessel Water Level Low - Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level Low - Level 3 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level Low - Level 3 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level Low - Level 3 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level Low - Level 3 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 2 valves.

Reactor Water Cleanup (RWCU) System Isolation - Reactor Vessel Water Level - Low, Low - Level 2

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor

INSTRUMENTATION

BASES

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

Vessel Water Level - Low, Low - Level 2 Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System. Reactor Vessel Water Level - Low, Low - Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level - Low, Low - Level 2 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level - Low, Low - Level 2 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level - Low, Low Level 2 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level - Low, Low Level 2 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 3 valves.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Actions

A note has been provided to modify the ACTIONS related to RPV Water Inventory Control instrumentation channels. The ACTIONS for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for each inoperable RPV Water Inventory Control instrumentation channel.

ACTION a. directs taking the appropriate ACTION referenced in Table 3.3.3.A-1. The applicable ACTION referenced in the table is Function dependent.

RHR System Shutdown Cooling Mode Isolation, Reactor Vessel Water Level Low - Level 3, and Reactor Water Cleanup System Isolation, Reactor Vessel Water Level - Low, Low - Level 2 functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. If the instrumentation is inoperable, ACTION 38 directs immediate action to place the channel in trip. With the inoperable channel in the tripped condition, the remaining channel will isolate the penetration flow path on low water level. If both channels are inoperable and placed in trip, the penetration flow path will be isolated. Alternatively, ACTION 38 requires the associated penetration flow path(s) to be immediately declared incapable of automatic isolation and directs initiating action to calculate of DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

INSTRUMENTATION

BASES

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.
2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.
3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.
4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.
5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

INSTRUMENTATION

BASES

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 175 ms. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression, and the response time of the system logic.

INSTRUMENTATION

BASES

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

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INSTRUMENTATION

BASES

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that: (1) the radiation levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded, and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63, and 64.

The surveillance interval for the Main Control Room Normal Fresh Air Supply Radiation Monitor is determined in accordance with the Surveillance Frequency Control Program.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

3/4.3.7.2 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.7.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.4 REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

The OPERABILITY of the remote shutdown system instrumentation and controls ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criterion 19 of 10 CFR Part 50, Appendix A.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 2, requires two OPERABLE channels of Reactor Vessel Water Level monitoring from each of two overlapping instrumentation loops to ensure monitoring of Reactor Vessel Water Level over the range of -350 inches to +60 inches. Each channel is comprised of one OPERABLE Wide Range Level instrument loop (-150 inches to +60 inches) and one OPERABLE Fuel Zone Range instrument loop (-350 inches to -100 inches). Both instrument loops, Wide Range and Fuel Zone Range, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (Wide Range and Fuel Zone Range) is not maintained.

LIMERICK - UNIT 1

B 3/4 3-5

Amendment No. 48, 53, 70, 75, 151,
~~ECR-02-00470, 173, 186, ECR-LG-09-00585,~~
Associated with Amendment 256

INSTRUMENTATION

BASES

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION (continued)

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 13, requires two OPERABLE channels of Neutron Flux monitoring from each of three overlapping instrumentation loops to ensure monitoring of Neutron Flux over the range of $10^{-6}\%$ to 100% full power. Each channel is comprised of one OPERABLE SRM ($10^{-9}\%$ to $10^{-3}\%$ power), one OPERABLE IRM ($10^{-4}\%$ to 40% power) and one OPERABLE APRM (0% to 125% power). All three instrument loops, SRM, IRM and APRM, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (SRM, IRM, and APRM) is not maintained.

3/4.3.7.6 SOURCE RANGE MONITORS

The source range monitors provide the operator with information of the status of the neutron level in the core at very low power levels during startup and shutdown. At these power levels, reactivity additions shall not be made without this flux level information available to the operator. When the intermediate range monitors are on scale, adequate information is available without the SRMs and they can be retracted.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

INSTRUMENTATION

BASES

3/4.3.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.8 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.9 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

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INSTRUMENTATION

BASES

3/4.3.7.10 (Deleted)

3/4.3.7.11 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.12 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM AND THE TRM.

3/4.3.8 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

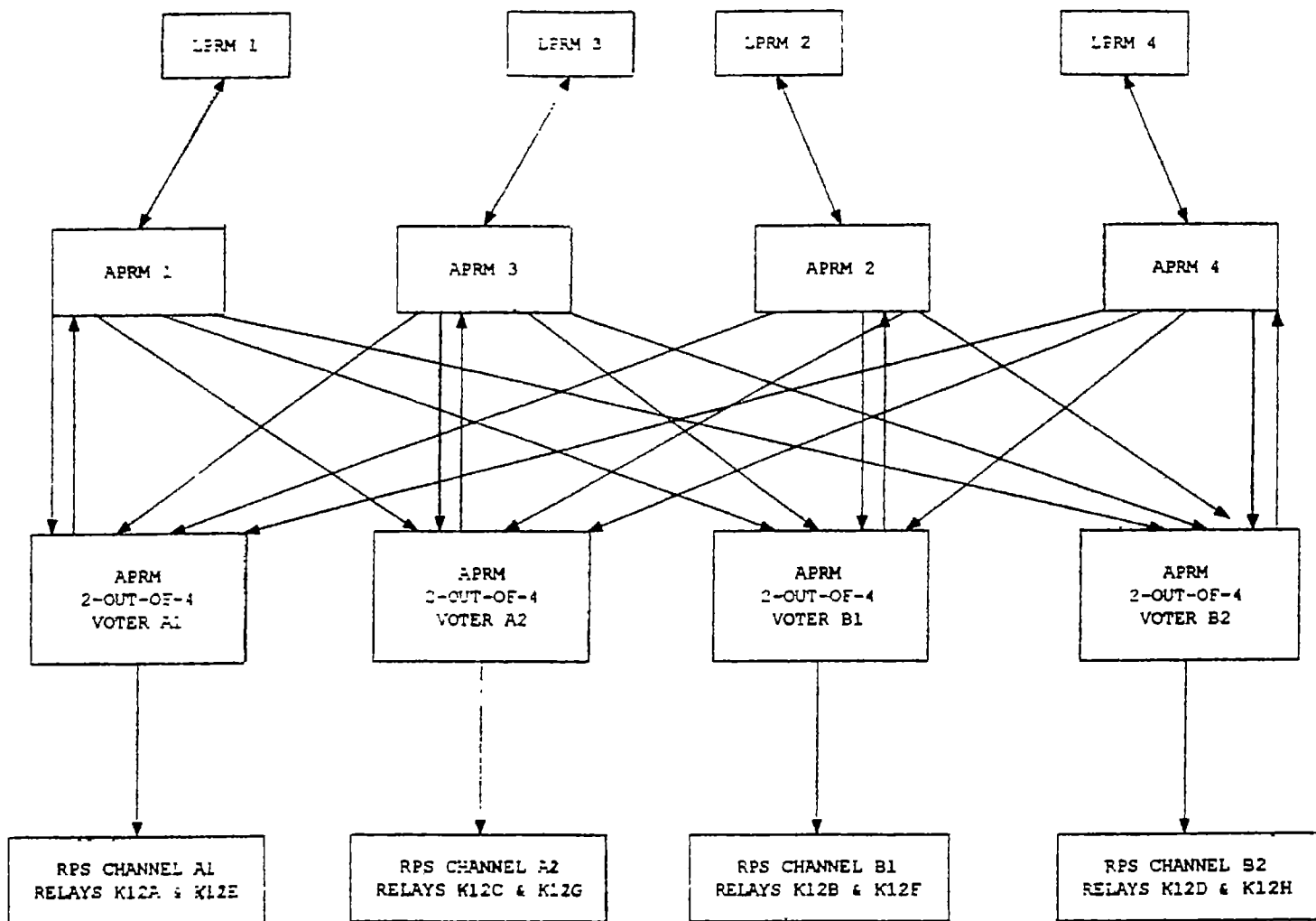
3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

The feedwater/main turbine trip system actuation instrumentation is provided to initiate action of the feedwater system/main turbine trip system in the event of failure of feedwater controller under maximum demand.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

REFERENCES:

1. NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.
2. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," October 1995.
3. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," November 1997.
4. NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.
5. NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.
6. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.
7. Letter, L. A. England (BWROG) to M. J. Virgilio, "BWR Owners' Group Guidelines for Stability Interim Corrective Action," June 6, 1994.
8. GE Service Information Letter No. 516, "Core Flow Measurement - GE BWR/3, 4, 5 and 6 Plants," July 26, 1990.
9. GE Letter NSA 00-433, Alan Chung (GE) to Sujit Chakraborty (GE), "Minimum Number of Operable OPRM Cells for Option III Stability at Limerick 1 & 2," May 02, 2001.



BASES FIGURE B 3/4.3-2

APRM CONFIGURATION

APR 12 2000

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3/4.4. REACTOR COOLANT SYSTEM

BASES

3/4.4.1 RECIRCULATION SYSTEM

The impact of single recirculation loop operation upon plant safety is assessed and shows that single-loop operation is permitted if the MCPR(99.9%) is increased as noted in the COLR, APRM scram and control rod block setpoints are adjusted as noted in Tables 2.2.1-1 and 3.3.6-2, respectively.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis-accident, increase the blowdown area and reduce the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

Additionally, surveillance on the pump speed of the operating recirculation loop is imposed to exclude the possibility of excessive internal vibration. The surveillance on differential temperatures below 30% RATED THERMAL POWER or 50% rated recirculation loop flow is to mitigate the undue thermal stress on vessel nozzles, recirculation pump and vessel bottom head during the extended operation of the single recirculation loop mode.

Surveillance of recirculation loop flow, total core flow, and diffuser-to-lower plenum differential pressure is designed to detect significant degradation in jet pump performance that precedes jet pump failure. This surveillance is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns," engineering judgment of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (pump flow and loop flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

REACTOR COOLANT SYSTEM

BASES

3/4.4.1 RECIRCULATION SYSTEM (continued)

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system. Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data.

Recirculation pump speed mismatch limits are in compliance with the ECCS LOCA analysis design criteria for two recirculation loop operation. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA. In the case where the mismatch limits cannot be maintained during two loop operation, continued operation is permitted in a single recirculation loop mode.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Sudden equalization of a temperature difference > 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1325 psig in accordance with the ASME Code. A total of 12 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case upset transient.

Demonstration of the safety/relief valve lift settings will occur only during shutdown. The safety/relief valves will be removed and either set pressure tested or replaced with spares which have been previously set pressure tested and stored in accordance with manufacturers recommendations at the frequency specified in the Surveillance Frequency Control Program.

REACTOR COOLANT SYSTEM

BASES

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

BACKGROUND

UFSAR Safety Design Basis (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of Reactor Coolant System (RCS) PRESSURE BOUNDARY LEAKAGE. Regulatory Guide 1.45, Revision 0, (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on leakage from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms.

Systems for quantifying the leakage are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action. Leakage from the RCPB inside the drywell is detected by at least one of four (4) independently monitored variables which include drywell sump flow monitoring equipment with the required RCS leakage detection instrumentation (i.e., the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump), drywell gaseous radioactivity, drywell unit cooler condensate flow rate and drywell pressure/temperature levels. The primary means of quantifying leakage in the drywell is the drywell sump monitoring system for UNIDENTIFIED LEAKAGE and the drywell equipment drain tank flow monitoring system for IDENTIFIED LEAKAGE. IDENTIFIED leakage is not germane to this Tech Spec and the associated drywell equipment drain tank flow monitoring system is not included.

The drywell floor drain sump flow monitoring system monitors UNIDENTIFIED LEAKAGE collected in the floor drain sump. UNIDENTIFIED LEAKAGE consists of leakage from RCPB components inside the drywell which are not normally subject to leakage and otherwise routed to the drywell equipment drain sump. The primary containment floor drain sump has transmitters that supply level indication to the main control room via the plant monitoring system. The floor drain sump level transmitters are associated with High/Low level switches that open/close the sump tank drain valves automatically. The level instrument processing unit calculates an average leak rate (gpm) for a given measurement period which resets whenever the sump drain valve closes. The level processing unit provides an alarm to the main control room each time the average leak rate changes by a predetermined value since the last time the alarm was reset. For the drywell floor drain sump flow monitoring system, the setpoint basis is a 1 gpm change in UNIDENTIFIED LEAKAGE.

An alternate to the drywell floor drain sump flow monitoring system for quantifying UNIDENTIFIED LEAKAGE is the drywell equipment drain sump monitoring system, if the drywell floor drain sump is overflowing to the drywell equipment drain sump. In this configuration, the drywell equipment drain sump collects all leakage into the drywell equipment drain sump and the overflow from the drywell floor drain sump. Therefore, if the drywell floor drain sump is overflowing to the drywell equipment drain sump, the drywell equipment drain sump monitoring system can be used to quantify UNIDENTIFIED LEAKAGE. In this condition, all leakage measured by the drywell equipment drain sump monitoring system is assumed to be UNIDENTIFIED LEAKAGE. The leakage determination process, including the transition to and use of the alternate method is described in station procedures. The alternate method would only be used when the drywell floor drain sump flow monitoring system is unavailable.

In addition to the drywell sump monitoring system described above, the discharge of each sump is monitored by an independent flow element. The measured flow rate from the flow element is integrated and recorded. A main control room alarm is also provided to indicate an excessive sump discharge rate measured via the flow element. This system, referred to as the "drywell floor drain flow totalizer", is not credited for drywell floor drain sump flow monitoring system operability.

REACTOR COOLANT SYSTEM

BASES

BACKGROUND (Continued)

The primary containment atmospheric gaseous radioactivity monitoring system continuously monitors the primary containment atmosphere for gaseous radioactivity levels. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water leakage, is annunciated in the main control room.

Condensate from the eight drywell air coolers is routed to the drywell floor drain sump and is monitored by a series of flow transmitters that provide indication and alarms in the main control room. The outputs from the flow transmitters are added together by summing units to provide a total continuous condensate drain flow rate. The high flow alarm setpoint is based on condensate drain flow rate in excess of 1 gpm over the currently identified preset leak rate. The drywell air cooler condensate flow rate monitoring system serves as an added indicator, but not quantifier, of RCS UNIDENTIFIED LEAKAGE (Ref. 4).

The drywell temperature and pressure monitoring systems provide an indirect method for detecting RCPB leakage. A temperature and/or pressure rise in the drywell above normal levels may be indicative of a reactor coolant or steam leakage (Ref. 5).

APPLICABLE SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. Leakage rate limits are set low enough to detect the leakage emitted from a single crack in the RCPB (Refs. 6 and 7).

A control room alarm allows the operators to evaluate the significance of the indicated leakage and, if necessary, shut down the reactor for further investigation and corrective action. The allowed leakage rates are well below the rates predicted for critical crack sizes (Ref. 7). Therefore, these actions provide adequate responses before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

LIMITING CONDITION FOR OPERATION (LCO)

This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of UNIDENTIFIED LEAKAGE are detected in time to allow actions to place the plant in a safe condition, when RCS leakage indicates possible RCPB degradation.

The LCO requires four instruments to be OPERABLE.

The required instrumentation to quantify UNIDENTIFIED LEAKAGE from the RCS consists of either the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump. For either system to be considered operable, the flow monitoring portion of the system must be operable. The identification of an increase in UNIDENTIFIED LEAKAGE will be delayed by the time required for the UNIDENTIFIED LEAKAGE to travel to the drywell floor drain sump and it may take longer than one hour to detect a 1 gpm increase in UNIDENTIFIED LEAKAGE, depending on the origin and magnitude of the leakage. This sensitivity is acceptable for containment sump monitor OPERABILITY.

The reactor coolant contains radioactivity that, when released to the primary containment, can be detected by the gaseous primary containment atmospheric radioactivity monitor. A radioactivity detection system is included for monitoring gaseous activities because of its sensitivity and rapid response to RCS leakage, but it has recognized limitations. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous primary

REACTOR COOLANT SYSTEM

BASES

LIMITING CONDITION FOR OPERATION (LCO) (Continued)

containment atmospheric radioactivity monitor to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous primary containment atmospheric radioactivity monitor is OPERABLE when it is capable of detecting a 1 gpm increase in UNIDENTIFIED LEAKAGE within 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors (Reference 9).

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the drywell floor drain sump monitoring system in combination with a gaseous primary containment atmospheric radioactivity monitor, a primary containment air cooler condensate flow rate monitoring system, and a primary containment pressure and temperature monitoring system provides an acceptable minimum.

APPLICABILITY

In OPERATIONAL CONDITIONS 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.3.2. This applicability is consistent with that for LCO 3.4.3.2.

ACTIONS

- A. With the primary containment atmosphere gaseous monitoring system inoperable, grab samples of the primary containment atmosphere must be taken and analyzed to provide periodic leakage information. [Provided a sample is obtained and analyzed once every 12 hours, the plant may be operated for up to 30 days to allow restoration of the radioactivity monitoring system. The plant may continue operation since other forms of drywell leakage detection are available.]

The 12 hour interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time for Restoration recognizes other forms of leakage detection are available.

- B. With required drywell sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage at the required 1 gpm/hour sensitivity. However, the primary containment atmospheric gaseous monitor [and the primary containment air cooler condensate flow rate monitor] will provide indication of changes in leakage.

With required drywell sump monitoring system inoperable, drywell condensate flow rate monitoring frequency increased from 12 to every 8 hours, and UNIDENTIFIED LEAKAGE and total leakage being determined every 8 hours (Ref. SR 4.4.3.2.1.b) operation may continue for 30 days. To the extent practical, the surveillance frequency change associated with the drywell condensate flow rate monitoring system, makes up for the loss of the drywell floor drain monitoring system which had a normal surveillance requirement to monitor leakage every 8 hours. Also note that in this instance, the drywell floor drain tank flow totalizer will be used to comply with SR 4.4.3.2.1.b. The 30 day Completion Time of the required ACTION is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

- C. With the required primary containment air cooler condensate flow rate monitoring system inoperable, SR 4.4.3.1.a must be performed every 8 hours to provide periodic information of activity in the primary containment of more frequent interval than the routine frequency of every 12 hours. The 8 hour interval provides periodic information that is adequate to detect leakage and recognizes that other forms of leakage detection are available. The required ACTION has been clarified to state

REACTOR COOLANT SYSTEM

BASES

ACTIONS (Continued)

that the additional surveillance requirement is not applicable if the required primary containment atmosphere gaseous radioactivity monitoring system is also inoperable. Consistent with SR 4.0.3, surveillances are not required to be performed on inoperable equipment. In this case, ACTION Statement A. and E. requirements apply.

- D. With the primary containment pressure and temperature monitoring system inoperable, operation may continue for up to 30 days given the system's indirect capability to detect RCS leakage. However, other more limiting Tech Spec requirements associated with the primary containment pressure/temperature monitoring system will still apply.
- E. With both the primary containment atmosphere gaseous radioactivity monitor and the primary containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the drywell floor drain sump monitor and the drywell pressure/temperature instrumentation. This condition does not provide the required diverse means of leakage detection. The required ACTION is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period. While the primary containment atmosphere gaseous radioactivity monitor is INOPERABLE, primary containment atmospheric grab samples will be taken and analyzed every 12 hours since ACTION Statement A. requirements also apply.
- F. With the drywell floor drain sump monitoring system inoperable and the drywell unit coolers condensate flow rate monitoring system inoperable, one of the two remaining means of detecting leakage is the primary containment atmospheric gaseous radiation monitor. The primary containment atmospheric gaseous radiation monitor typically cannot detect a 1 gpm leak within one hour when RCS activity is low. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the primary containment atmosphere must be taken and analyzed and monitoring of RCS leakage by administrative means must be performed every 12 hours to provide alternate periodic information.

Administrative means of monitoring RCS leakage include monitoring and trending parameters that may indicate an increase in RCS leakage. There are diverse alternative mechanisms from which appropriate indicators may be selected based on plant conditions. It is not necessary to utilize all of these methods, but a method or methods should be selected considering the current plant conditions and historical or expected sources of UNIDENTIFIED LEAKAGE. The administrative methods are the drywell cooling fan inlet/outlet temperatures, drywell equipment drain sump temperature indicator, drywell equipment drain tank hi temperature indicator, and drywell equipment drain tank flow indicator. These indications, coupled with the atmospheric grab samples, are sufficient to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

In addition to the primary containment atmospheric gaseous radiation monitor and indirect methods of monitoring RCS leakage, the primary containment pressure and temperature monitoring system is also available to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

REACTOR COOLANT SYSTEM

BASES

ACTIONS (Continued)

The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to regain the intended leakage detection diversity. The 7-day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

- G. If any required ACTION of Conditions A, B, C, D, E or F cannot be met within the associated Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least HOT SHUTDOWN within 12 hours and COLD SHUTDOWN within the next 24 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the ACTIONS in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 4.4.3.1.a

This SR is for the performance of a CHANNEL CHECK of the required primary containment atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly.

SR 4.4.3.1.b

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

SR 4.4.3.1.c

The SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment.

SR 4.4.3.1.d

This SR provides a routine check of primary containment pressure and temperature for indirect evidence of RCS leakage.

REFERENCES

1. LGS UFSAR, Section 5.2.5.1.
2. Regulatory Guide 1.45, Revision 0, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.
3. LGS UFSAR, Section 5.2.5.2.1.3.
4. LGS UFSAR, Section 5.2.5.2.1.4.
5. LGS UFSAR, Section 5.2.5.2.1.1(2).
6. GEAP-5620, April 1968
7. NUREG-75/067, October 1975.
8. LGS UFSAR, Section 5.2.5.6.
9. LGS UFSAR, Section 5.2.5.2.1.5

REACTOR COOLANT SYSTEM

BASES

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified, the reactor will be shutdown to allow further investigation and corrective action. The limit of 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period and the monitoring of drywell floor drain sump and drywell equipment drain tank flow rate at least once every eight (8) hours conforms with NRC staff positions specified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," as revised by NRC Safety Evaluation dated March 6, 1990. The ACTION requirement for the 2 gpm increase in UNIDENTIFIED LEAKAGE limit ensures that such leakage is identified or a plant shutdown is initiated to allow further investigation and corrective action. Separating the sources of LEAKAGE (i.e., LEAKAGE from an identified source versus LEAKAGE from an unidentified source) is necessary for prompt identification of potentially adverse conditions, assessment of the safety significance, and corrective action. Once identified, reactor operation may continue dependent upon the impact on total leakage.

PRESSURE BOUNDARY LEAKAGE is prohibited as the leak itself could cause further reactor coolant pressure boundary deterioration, resulting in higher leakage. If PRESSURE BOUNDARY LEAKAGE exists, the affected component, pipe, or vessel must be isolated from the reactor coolant system by a closed manual valve, closed and deactivated automatic valve, blind flange, or check valve within 4 hours. While in this condition, structural integrity of the system should be considered because the structural integrity of the part of the system within the isolation boundary must be maintained under all licensing basis conditions, including consideration of the potential for further degradation of the isolated location. Normal leakage past the isolation device is acceptable as it will limit reactor coolant system leakage and is included in IDENTIFIED LEAKAGE or UNIDENTIFIED LEAKAGE. This ACTION is necessary to prevent further deterioration of the reactor coolant pressure boundary. If the ACTION cannot be completed in the required time, then the reactor will be shutdown to allow further investigation and corrective action.

The function of Reactor Coolant System Pressure Isolation Valves (PIVs) is to separate the high pressure Reactor Coolant System from an attached low pressure system. The ACTION requirements for pressure isolation valves are used in conjunction with the system specifications for which PIVs are listed in the Technical Requirements Manual and with primary containment isolation valve requirements to ensure that plant operation is appropriately limited.

The Surveillance Requirements for the RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valves is not included in any other allowable operational leakage specified in Section 3.4.3.2.

3/4.4.4. (Deleted) INFORMATION FROM THIS SECTION RELOCATED TO THE TRM

REACTOR COOLANT SYSTEM

BASES

3/4.4.4 (Deleted) INFORMATION FROM THIS SECTION RELOCATED TO THE TRM

3/4.4.5 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses resulting from a main steam line failure outside the containment during steady state operation will not exceed small fractions of the dose guidelines of 10 CFR Part 100. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters, such as SITE BOUNDARY location and meteorological conditions, were not considered in this evaluation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity greater than 0.2 microcurie per gram DOSE EQUIVALENT I-131, but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131, accommodates possible iodine spiking phenomenon which may occur following changes in the THERMAL POWER. This action is modified by a Note that permits the use of the provisions of Specification 3.0.4.c. This allowance permits entry into the applicable OPERATIONAL CONDITION (S) while relying on the ACTION requirements. Operation with specific activity levels exceeding 0.2 microcurie per gram DOSE EQUIVALENT I-131 but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131 must be restricted since these activity levels increase the 2-hour thyroid dose at the SITE BOUNDARY following a postulated steam line rupture.

Closing the main steam line isolation valves prevents the release of activity to the environs should a steam line rupture occur outside containment. The surveillance requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in Section 3.9 of the FSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

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REACTOR COOLANT SYSTEM

BASES

PRESSURE/TEMPERATURE LIMITS (Continued)

The operating limit curves specified in the PTLR are derived from the fracture toughness requirements of 10 CFR 50 Appendix G and ASME Code Section XI, Appendix G. The curves are based on the RT_{NDT} and stress intensity factor information for the reactor vessel components. Fracture toughness limits and the basis for compliance are more fully discussed in FSAR Chapter 5, Paragraph 5.3.1.5, "Fracture Toughness."

The reactor vessel materials have been tested to determine their initial RT_{NDT} . The results of these tests are specified in the PTLR. Reactor operation and resultant fast neutron, E greater than 1 MeV, irradiation will cause an increase in the RT_{NDT} . Therefore, an adjusted reference temperature, based upon the fluence, nickel content and copper content of the material in question, can be predicted using the PTLR and the recommendations of Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." The pressure/temperature limit curves specified in the PTLR include an assumed shift in RT_{NDT} for the conditions at 57 EFPY.

The pressure-temperature limit lines specified in the PTLR for reactor criticality and for inservice leak and hydrostatic testing have been provided to assure compliance with the minimum temperature requirements of Appendix G to 10 CFR Part 50 for reactor criticality and for inservice leak and hydrostatic testing.

REACTOR COOLANT SYSTEM

BASES

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

Double isolation valves are provided on each of the main steam lines to minimize the potential leakage paths from the containment in case of a line break. Only one valve in each line is required to maintain the integrity of the containment, however, single failure considerations require that two valves be OPERABLE. The surveillance requirements are based on the operating history of this type valve. The maximum closure time has been selected to contain fission products and to ensure the core is not uncovered following line breaks. The minimum closure time is consistent with the assumptions in the safety analyses to prevent pressure surges.

3/4.4.8 (DELETED)

3/4.4.9 RESIDUAL HEAT REMOVAL

The RHR system is required to remove decay heat and sensible heat in order to maintain the temperature of the reactor coolant. RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR System can provide the required decay heat removal capability. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the associated recirculation loop or to the reactor via the low pressure coolant injection pathway. The RHR heat exchangers transfer heat to the RHR Service Water System. The RHR shutdown cooling mode is manually controlled.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. In HOT SHUTDOWN condition, the requirement to maintain OPERABLE two (2) independent RHR shutdown cooling subsystems means that each subsystem considered OPERABLE must be associated with a different heat exchanger loop, i.e., the "A" RHR heat exchanger with the "A" RHR pump or the "C" RHR pump, and the "B" RHR heat exchanger with the "B" RHR pump or the "D" RHR pump are two (2) independent RHR shutdown cooling subsystems. Only one (1) of the two (2) RHR pumps associated with each RHR heat exchanger loop is

REACTOR COOLANT SYSTEM

BASES

3/4.4.9 RESIDUAL HEAT REMOVAL (Continued)

required to be OPERABLE for that independent subsystem to be OPERABLE. During COLD SHUTDOWN and REFUELING conditions, however, the subsystems not only have a common suction source, but are allowed to have a common heat exchanger and common discharge piping. To meet the LCO of two (2) OPERABLE subsystems, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. Since the piping and heat exchangers are passive components, that are assumed not to fail, they are allowed to be common to both subsystems. Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one (1) subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Alternate decay heat removal methods are available to operators. These alternate methods of decay heat removal can be verified available either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration, and that a method of coolant mixing be operational. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensable gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to initially placing the system in operation during reactor shutdown. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System whose use is typically preceded by system piping flushes that disturb both the RHR pump suction and discharge piping. RHR Shutdown Cooling System is flushed and manually aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. In the event that RHR Shutdown Cooling is required for emergency service, the system operating procedures that align and start the RHR System in shutdown cooling mode include the flexibility to eliminate piping flushes while maintaining minimum requirements to ensure that the suction and discharge flow paths are sufficiently filled with water. The RHR Shutdown Cooling System surveillance is met through the performance of the operating procedures that initially place the RHR shutdown cooling sub-system in service.

This surveillance requirement is modified by a Note allowing sufficient time (12 hours) to align the RHR System for Shutdown Cooling operation after reactor dome pressure is less than the RHR cut-in permissive set point.

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Amendment No. 33, 106, 253

3/4.5 EMERGENCY CORE COOLING SYSTEM

BASES

3/4.5.1 ECCS - OPERATING

The core spray system (CSS), together with the LPCI mode of the RHR system, is provided to assure that the core is adequately cooled following a loss-of-coolant accident and provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS. Management of gas voids is important to ECCS injection/spray subsystem OPERABILITY.

The CSS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the CSS will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. Four subsystems, each with one pump, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

The surveillance requirements provide adequate assurance that the LPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

The high pressure coolant injection (HPCI) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the reactor coolant system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCI system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HPCI system continues to operate until reactor vessel pressure is below the pressure at which CSS operation or LPCI mode of the RHR system operation maintains core cooling.

The capacity of the system is selected to provide the required core cooling. The HPCI pump is designed to deliver greater than or equal to 5600 gpm at reactor pressures between 1182 and 200 psig and is capable of delivering at least 5000 gpm between 1182 and 1205 psig. In the system's normal alignment, water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor, but no credit is taken in the safety analyses for the condensate storage tank water.

EMERGENCY CORE COOLING SYSTEM

BASES

ECCS - OPERATING (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. The HPCI system, and one LPCI subsystem, and/or one CSS subsystem out-of-service period of 8 hours ensures that sufficient ECCS, comprised of a minimum of one CSS subsystem, three LPCI subsystems, and all of the ADS will be available to 1) provide for safe shutdown of the facility, and 2) mitigate and control accident conditions within the facility. Alternatively, the out-of-service times described above can be determined in accordance with the Risk Informed Completion Time Program. A Note prohibits the application of Specification 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown.

During plant startup, when the HPCI surveillance test is being performed, HPCI is required to be tested within 12 hours of changing modes. The intent of this requirement is to verify operability prior to reaching any significant power. If HPCI is not successfully demonstrated operable within the 12-hour period, the reactor steam dome pressure must be reduced to less than 200 psig within the following 72 hours. The intent of the action is to hold pressure at a point where sufficient steam is available to test the pump; it does not permit power ascension to continue.

The ECCS injection/spray subsystem flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS injection/spray subsystems and may also prevent a water hammer, pump cavitation, and pumping of noncondensable gas into the reactor vessel.

Selection of ECCS injection/spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The ECCS injection/spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits. ECCS injection/spray

EMERGENCY CORE COOLING SYSTEM

BASES

ECCS - OPERATING (Continued)

subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.5.1.a.1.b is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed:

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety/relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls five selected safety-relief valves. The safety analysis assumes all five are operable. The allowed out-of-service time for one valve for up to fourteen days is determined in a similar manner to other ECCS subsystem out-of-service time allowances. Alternatively, the allowed out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

Verification that ADS accumulator gas supply header pressure is ≥90 psig ensures adequate gas pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator at least two valve actuations can occur with the drywell at 70% of design pressure. The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥90 psig is provided by the PCIG supply.

EMERGENCY CORE COOLING SYSTEM

BASES

3/4.5.2 - REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC)

Background:

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Applicable Safety Analysis:

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material to the environment should an unexpected draining event occur.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure (an event that creates a drain path through multiple vessel penetrations located below top of active fuel, such as loss of normal power, or a single human error). It is assumed, based on engineering judgement, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Limiting Condition for Operation:

The RPV water level must be controlled in OPERATIONAL CONDITIONS 4 and 5 to ensure that if an unexpected draining event should occur, the reactor coolant water level remains above the top of the active irradiated fuel as required by Safety Limit 2.1.4.

The Limiting Condition for Operation (LCO) requires the DRAIN TIME of RPV water inventory to the TAF to be ≥ 36 hours. A DRAIN TIME of 36 hours is considered reasonable to identify and initiate action to mitigate unexpected draining of reactor coolant. An event that could cause loss of RPV water inventory and result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.4 and can be managed as part of normal plant operation.

One low pressure ECCS injection/spray subsystem is required to be OPERABLE and capable of being manually aligned and started from the control room to provide defense-in-depth should an unexpected draining event occur. OPERABILITY of the ECCS injection/spray subsystem includes any necessary valves, instrumentation, or controls needed to manually align and start the subsystem from the control room. A low pressure ECCS injection/spray subsystem consists of either one Core Spray System (CSS) subsystem or one Low Pressure Coolant Injection (LPCI) subsystem. Each CSS subsystem consists of two motor driven pumps, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV. Each LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV.

EMERGENCY CORE COOLING SYSTEM

BASES

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The LCO is modified by a note which allows a required LPCI subsystem to be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. This allowance is necessary since the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Because of the restrictions on DRAIN TIME, sufficient time will be available following an unexpected draining event to manually align and initiate LPCI subsystem operation to maintain RPV water inventory prior to the RPV water level reaching the TAF.

Applicability:

RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5. Requirements on water inventory control are contained in LCO 3.3.3.A, REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION, and LCO 3.5.2, REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC). RPV water inventory control is required to protect Safety Limit 2.1.4 which is applicable whenever irradiated fuel is in the reactor vessel.

Actions:

Action a. - If none of the required low pressure ECCS injection/spray subsystems are OPERABLE, one subsystem must be restored to OPERABLE status within 4 hours. In this condition, the LCO controls on DRAIN TIME minimize the possibility that an unexpected draining event could necessitate the use of the ECCS injection/spray subsystem; however, the defense-in-depth provided by the ECCS injection/spray subsystem is lost. The 4-hour allowed outage time for restoring the required low pressure ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considers the LCO controls on DRAIN TIME and the low probability of an unexpected draining event that would result in loss of RPV water inventory.

If the inoperable ECCS injection/spray subsystem is not restored to OPERABLE status within 4 hours, action must be initiated immediately to establish a method of water injection capable of operating without offsite electrical power. The method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The method of water injection may be manually initiated and may consist of one or more systems or subsystems, and must be able to access water inventory capable of maintaining the RPV water level above the TAF for ≥ 36 hours. If recirculation of injected water would occur, it may be credited in determining the necessary water volume.

Action b. - Deleted

Action c. - With the DRAIN TIME less than 36 hours but greater than or equal to 8 hours, compensatory measures should be taken to ensure the ability to implement mitigating actions should an unexpected draining event occur. Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

EMERGENCY CORE COOLING SYSTEM

BASES

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The secondary containment provides a controlled volume in which fission products can be contained, diluted, and processed prior to release to the environment. Verification of the capability to establish SECONDARY CONTAINMENT INTEGRITY in less than the DRAIN TIME is required. The required verification confirms actions to establish SECONDARY CONTAINMENT INTEGRITY are preplanned and necessary materials are available. SECONDARY CONTAINMENT INTEGRITY is considered established when one Standby Gas Treatment (SGT) subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment. Verification that SECONDARY CONTAINMENT INTEGRITY can be established must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Secondary containment penetration flow paths form a part of SECONDARY CONTAINMENT INTEGRITY. Verification of the capability to isolate each secondary containment penetration flow path in less than the DRAIN TIME is required. The required verification confirms actions to isolate secondary containment penetration flow paths are preplanned and necessary materials are available. Power operated valves are not required to receive automatic isolation signals if they can be closed manually within the required time. Verification that secondary containment penetration flow paths can be isolated must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

One SGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Verification of the capability to place one SGT subsystem in operation in less than the DRAIN TIME is required. The required verification confirms actions to place a SGT subsystem in operation are preplanned and necessary materials are available. Verification that a SGT subsystem can be placed in operation must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Action d. - With the DRAIN TIME less than 8 hours, mitigating actions are implemented in case an unexpected draining event should occur. Note that if the DRAIN TIME is less than 1 hour, the required Action e. to restore DRAIN TIME to 36 hours or greater is also applicable.

Immediate action to establish an additional method of water injection augmenting the ECCS injection/spray subsystem required by the LCO is required. The additional method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The note states that either the ECCS injection/spray subsystem or the additional method of water injection must be capable of operating without offsite electrical power. The additional method of water injection may be manually initiated and may consist of one or more systems or subsystems. The additional method of water injection must be able to access water inventory capable of being injected to maintain the RPV water level above the TAF for ≥ 36 hours. The additional method of water injection and the ECCS injection/spray subsystem may share all or part of the same water sources. If recirculation of injected water would occur, it may be credited in determining the required water volume.

Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

EMERGENCY CORE COOLING SYSTEM

BASES

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The secondary containment provides a control volume into which fission products can be contained, diluted, and processed prior to release to the environment. Actions to immediately establish SECONDARY CONTAINMENT INTEGRITY are required. With SECONDARY CONTAINMENT INTEGRITY established, one SGT subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment.

The secondary containment penetrations form a part of SECONDARY CONTAINMENT INTEGRITY. Actions to immediately verify that each secondary containment penetration flow path is isolated or to verify that it can be automatically or manually isolated from the control room are required.

One SGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Actions to immediately verify that at least one SGT subsystem is capable of being placed in operation are required. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Action e. - If the ACTIONS and associated allowed outage times are not met or if the DRAIN TIME is less than 1 hour, actions must be initiated immediately to restore the DRAIN TIME to ≥ 36 hours. In this condition, there may be insufficient time to respond to an unexpected draining event to prevent the RPV water inventory from reaching the TAF. Note that ACTIONS are also applicable when DRAIN TIME is less than 1 hour.

Surveillance Requirements:

Surveillance Requirement (SR) 4.5.2.1 verifies that the DRAIN TIME of RPV water inventory to the TAF is ≥ 36 hours. The period of 36 hours is considered reasonable to identify and initiate action to mitigate draining of reactor coolant. Loss of RPV water inventory that would result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.4 and can be managed as part of normal plant operation.

The definition of DRAIN TIME states that realistic cross-sectional areas and drain rates are used in the calculation. A realistic drain rate may be determined using a single, step-wise, or integrated calculation considering the changing RPV water level during a draining event. For a control rod RPV penetration flow path with the control rod drive mechanism removed and not replaced with a blank flange, the realistic cross-sectional area is based on the control rod blade seated in the control rod guide tube. If the control rod blade will be raised from the penetration to adjust or verify seating of the blade, the exposed cross-sectional area of the RPV penetration flow path is used.

The definition of DRAIN TIME excludes from the calculation those penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are closed and administratively controlled, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths. A blank flange or other bolted device must be connected with a sufficient number of bolts to prevent draining. Normal or expected leakage from closed systems or past isolation devices is permitted. Determination that a system is intact and closed or isolated must consider the status of branch lines.

The Residual Heat Removal (RHR) Shutdown Cooling System is only considered an intact closed system when misalignment issues (Reference 6) have been precluded by functional valve interlocks or by isolation devices, such that redirection of RPV water out of an RHR subsystem is precluded. Further, the RHR Shutdown Cooling System is only considered an intact closed system if its controls have not been transferred to Remote Shutdown, which disables the interlocks and isolation signals.

EMERGENCY CORE COOLING SYSTEM

BASES

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The exclusion of a single penetration flow path, or multiple penetration flow paths susceptible to a common mode failure, from the determination of DRAIN TIME should consider the effects of temporary alterations in support of maintenance (rigging, scaffolding, temporary shielding, piping plugs, freeze seals, etc.). If reasonable controls are implemented to prevent such temporary alterations from causing a draining event from a closed system or between the RPV and the isolation device, the effect of the temporary alterations on DRAIN TIME need not be considered. Reasonable controls include, but are not limited to, controls consistent with the guidance in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 4, NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," or commitments to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."

TS 4.0.1 requires SRs to be met between performances. Therefore, any changes in plant conditions that would change the DRAIN TIME requires that a new DRAIN TIME be determined.

SRs 4.5.2.2 and 4.5.2.3 - The minimum water level of 16 feet required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the CSS subsystem or LPCI subsystem pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, the required ECCS injection/spray subsystem is inoperable unless aligned to an OPERABLE CST.

The required CSS subsystem is OPERABLE if it can take suction from the CST, and the CST water level is sufficient to provide the required NPSH for the CSS pumps. Therefore, a verification that either the suppression pool water level is greater than or equal to 16 feet 0 inches or that a CSS subsystem is aligned to take suction from the CST and the CST contains greater than or equal to 135,000 available gallons of water, equivalent to a level of 29 feet 0 inches, ensures that the CSS subsystem can supply the required makeup water to the RPV.

SR 4.5.2.4 - The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the required ECCS injection/spray subsystems full of water ensures that the ECCS subsystem will perform properly. This may also prevent a water hammer following an ECCS actuation. One acceptable method of ensuring that the lines are full is to vent at the high points.

SR 4.5.2.5 - DELETED

SR 4.5.2.6 - Verifying that the required ECCS injection/spray subsystem can be manually aligned, and the pump started and operate for at least 10 minutes demonstrates that the subsystem is available to mitigate a draining event. This surveillance requirement is modified by two footnotes. The first states that testing the ECCS injection/spray subsystem may be done through the test return line to avoid overfilling the refueling cavity. The second states that credit for meeting the surveillance requirement may be taken for normal system operation that satisfies the surveillance requirement, such as using the RHR mode of LPCI for greater than or equal to 10 minutes. The minimum operating time of 10 minutes was based on engineering judgement.

SR 4.5.2.7 - Verifying that each valve credited for automatically isolating a penetration flow path actuates to the isolation position on an actual or simulated RPV water level isolation signal is required to prevent RPV water inventory from dropping below the TAF should an unexpected draining event occur.

EMERGENCY CORE COOLING SYSTEM

BASES

RPV WATER INVENTORY CONTROL (WIC) (Continued)

SR 4.5.2.8 - This surveillance verifies that a required CSS subsystem or LPCI subsystem can be manually aligned and started from the control room, including any necessary valve alignment, instrumentation, or controls, to transfer water from the suppression pool or CST to the RPV.

The Surveillance Frequencies in the above SRs are controlled under the Surveillance Frequency Controlled Program.

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.
2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.
3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.
4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.
5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.
6. General Electric Service Information Letter No. 388, "RHR Valve Misalignment During Shutdown Cooling Operation for BWR 3/4/5/6," February 1983.

EMERGENCY CORE COOLING SYSTEM

BASES

3/4.5.3 SUPPRESSION CHAMBER

The suppression chamber is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCI, CS and LPCI systems in the event of a LOCA. This limit on suppression chamber minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression chamber in OPERATIONAL CONDITION 1, 2, or 3 is also required by Specification 3.6.2.1.

EMERGENCY CORE COOLING SYSTEM

BASES

RPV WATER INVENTORY CONTROL (WIC) (Continued)

SR 4.5.2.8 - The required ECCS subsystem is required to actuate on a manual initiation signal. This surveillance verifies that a manual initiation signal will cause the required CSS subsystem or LPCI subsystem to start and operate as designed, including pump startup and actuation of all automatic valves to their required positions. This SR is modified by a note that excludes vessel injection/spray during the surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the surveillance.

The Surveillance Frequencies in the above SRs are controlled under the Surveillance Frequency Controlled Program.

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.
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6. General Electric Service Information Letter No. 388, "RHR Valve Misalignment During Shutdown Cooling Operation for BWR 3/4/5/6," February 1983.

EMERGENCY CORE COOLING SYSTEM

BASES

3/4.5.3 SUPPRESSION CHAMBER

The suppression chamber is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCI, CS and LPCI systems in the event of a LOCA. This limit on suppression chamber minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression chamber in OPERATIONAL CONDITION 1, 2, or 3 is also required by Specification 3.6.2.1.

3/4.6 CONTAINMENT SYSTEMS

BASES

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

3/4.6.1.2 PRIMARY CONTAINMENT LEAKAGE

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value calculated in the safety analyses at the design basis LOCA maximum peak containment pressure of 44 psig, Pa. As an added conservatism, the measured overall integrated leakage rate (Type A Test) is further limited to less than or equal to 0.75 La during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

Operating experience with the main steam line isolation valves has indicated that degradation has occasionally occurred in the leak tightness of the valves; therefore the special requirement for testing these valves.

The surveillance testing for measuring leakage rates is consistent with the Primary Containment Leakage Rate Testing Program.

Limerick has an approved license amendment to implement 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors", and may voluntarily comply with the treatment requirements of 10 CFR 50.69 as an alternative to compliance with the Type B and Type C leakage testing requirements of 10 CFR 50, Appendix J for Risk-Informed Safety Classification (RISC) RISC-3 or RISC-4 penetrations and valves meeting the following criteria:

- A. Containment penetrations that are either 1-inch nominal size or less, or continuously pressurized.
- B. Containment isolation valves that meet one or more of the following criteria.
 - 1. The valve is required to be open under accident conditions to prevent or mitigate core damage events;
 - 2. The valve is normally closed and in a physically closed, water-filled system;
 - 3. The valve is in a physically closed system whose piping pressure rating exceeds the containment design pressure rating and is not connected to the reactor coolant pressure boundary; or
 - 4. The valve is 1-inch nominal size or less.

RISC-3 penetrations and valves that meet the criteria above may be removed from the scope of the Primary Containment Leakage Rate Testing Program, as implemented by Technical Specifications 3.6.1, 4.6.1 and 6.8.4.g. Alternative Treatment will be implemented in accordance with the requirements of 10 CFR 50.69(d).

3/4.6 CONTAINMENT SYSTEMS

BASES

3/4.6.1.3 PRIMARY CONTAINMENT AIR LOCK

The limitations on closure and leak rate for the primary containment air lock are required to meet the restrictions on PRIMARY CONTAINMENT INTEGRITY and the Primary Containment Leakage Rate Testing Program. Only one closed door in the air lock is required to maintain the integrity of the containment.

3/4.6.1.4 MSIV LEAKAGE ALTERNATE DRAIN PATHWAY

Calculated doses resulting from the maximum leakage allowances for the main steamline isolation valves in the postulated LOCA situations will not exceed the criteria of 10 CFR Part 100 guidelines, provided the main steam line system from the isolation valves up to and including the turbine condenser remains intact. Operating experience has indicated that degradation has occasionally occurred in the leak tightness of the MSIVs such that the specified leakage requirements have not always been continuously maintained. The requirement for the MSIV Leakage Alternate Drain Pathway serves to reduce the offsite dose.

CONTAINMENT SYSTEMS

BASES

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum calculated pressure in the event of a LOCA. A visual inspection in accordance with the Primary Containment Leakage Rate Testing Program is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the calculated containment peak pressure does not exceed the design pressure of 55 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5.0 psid. The limit of - 1.0 to + 2.0 psig for initial containment pressure will limit the total pressure to ≤ 44 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions and is consistent with the safety analysis.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The drywell and suppression chamber purge supply and exhaust isolation valves are required to be closed during plant operation except as required for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. Limiting the use of the drywell and suppression chamber purge system to specific criteria is imposed to protect the integrity of the SGTS filters. Analysis indicates that should a LOCA occur while this pathway is being utilized, the associated pressure surge through the (18 or 24") purge lines will adversely affect the integrity of SGTS. This condition is not imposed on the 1 and 2 inch valves used for pressure control since a surge through these lines does not threaten the operability of SGTS.

Surveillance requirement 4.6.1.8 ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by a Note stating that primary containment purge valves are only required to be closed in OPERATIONAL CONDITIONS 1, 2 and 3. The SR is also modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 or 24 inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time.

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CONTAINMENT SYSTEMS

BASES

3/4.6.2 DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure of 55 psig during primary system blowdown from full operating pressure. Management of gas voids is important to Suppression Pool Cooling/Spray Subsystem OPERABILITY.

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from rated conditions. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss-of-coolant accident, the pressure of the suppression chamber air space must not exceed 55 psig. The design volume of the suppression chamber, water and air, was obtained by considering that the total volume of reactor coolant is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in this specification, suppression pool pressure during the design basis accident is below the design pressure. Maximum water volume of 134,600 ft³ results in a downcomer submergence of 12'3" and the minimum volume of 122,120 ft³ results in a submergence approximately 2'3" less. The majority of the Bodega tests were run with a submerged length of 4 feet and with complete condensation. Thus, with respect to the downcomer submergence, this specification is adequate. The maximum temperature at the end of the blowdown tested during the Humboldt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperature above 170°F.

Should it be necessary to make the suppression chamber inoperable, this shall only be done as specified in Specification 3.5.3.

Under full power operating conditions, blowdown through safety/relief valves assuming an initial suppression chamber water temperature of 95°F results in a bulk water temperature of approximately 140°F immediately following blowdown which is below the 190°F bulk temperature limit used for complete condensation via T-quencher devices. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is no dependency on containment overpressure during the accident injection phase. If both RHR loops are used for containment cooling, there is no dependency on containment overpressure for post-LOCA operations.

CONTAINMENT SYSTEMS

BASES

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

RHR Suppression Pool Cooling/Spray subsystem piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR suppression pool subsystems and may also prevent water hammer and pump cavitation.

Selection of RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR Suppression Pool Cooling/Spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

One of the surveillance requirements for the suppression pool cooling (SPC) mode of the RHR system is to demonstrate that each RHR pump develops a flow rate $\geq 10,000$ gpm while operating in the SPC mode with flow through the heat exchanger and its associated closed bypass valve, ensuring that pump performance has not degraded during the cycle and that the flow path is operable. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component operability, trend performance and detect incipient failures by indicating abnormal performance. The RHR heat exchanger bypass valve is used for adjusting flow through the heat exchanger, and is not designed to be a tight shut-off valve. With the bypass valve closed, a portion of the total flow still travels through the bypass, which

CONTAINMENT SYSTEMS

BASES

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

can affect overall heat transfer. However, no heat transfer performance requirement of the heat exchanger is intended by the current Technical Specification surveillance requirement. This is confirmed by the lack of any flow requirement for the RHRSW system in Technical Specifications Section 3/4.7.1. Verifying an RHR flowrate through the heat exchanger does not demonstrate heat removal capability in the absence of a requirement for RHRSW flow. LGS does perform heat transfer testing of the RHR heat exchangers as part of its response to Generic Letter 89-13, which verified the commitment to meet the requirements of GDC 46.

Experimental data indicate that excessive steam condensing loads can be avoided if the peak local temperature of the suppression pool is maintained below 200°F during any period of relief valve operation for T-quencher devices. Specifications have been placed on the envelope of reactor operating conditions so that the reactor can be depressurized in a timely manner to avoid the regime of potentially high suppression chamber loadings.

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitoring these parameters daily is sufficient to establish any temperature trends. By requiring the suppression pool temperature to be frequently recorded during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken.

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

During a LOCA, potential leak paths between the drywell and suppression chamber airspace could result in excessive containment pressures, since the steam flow into the airspace would bypass the heat sink capabilities of the chamber. Potential sources of bypass leakage are the suppression chamber-to-drywell vacuum breakers (VBs), penetrations in the diaphragm floor, and cracks in the diaphragm floor and/or liner plate and downcomers located in the suppression chamber airspace. The containment pressure response to the postulated bypass leakage can be mitigated by manually actuating the suppression chamber sprays. An analysis was performed for a design bypass leakage area of A/\sqrt{k} equal to 0.0500 ft² to verify that the operator has sufficient time to initiate the sprays prior to exceeding the containment design pressure of 55 psig. The limit of 10% of the design value of 0.0500 ft² ensures that the design basis for the steam bypass analysis is met.

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CONTAINMENT SYSTEMS

BASES

DEPRESSURIZATION SYSTEMS (Continued)

The drywell-to-suppression chamber bypass test at a differential pressure of at least 4.0 psi verifies the overall bypass leakage area for simulated LOCA conditions is less than the specified limit. For those outages where the drywell-to-suppression chamber bypass leakage test is not conducted, the VB leakage test verifies that the VB leakage area is less than the bypass limit, with a 76% margin to the bypass limit to accommodate the remaining potential leakage area through the passive structural components. Previous drywell-to-suppression chamber bypass test data indicates that the bypass leakage through the passive structural components will be much less than the 76% margin. The VB leakage limit, combined with the negligible passive structural leakage area, ensures that the drywell-to-suppression chamber bypass leakage limit is met for those outages for which the drywell-to-suppression chamber bypass test is not scheduled.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The scram discharge volume vent and drain valves serve a dual function, one of which is primary containment isolation. Since the other safety functions of the scram discharge volume vent and drain valves would not be available if the normal PCIV actions were taken, actions are provided to direct the user to the scram discharge volume vent and drain operability requirements contained in Specification 3.1.3.1. However, since the scram discharge volume vent and drain valves are PCIVs, the Surveillance Requirements of Specification 4.6.3 still apply to these valves.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.6.3 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

Primary containment isolation valves governed by this Technical Specification are identified in Table 3.6.3-1 of the TRM.

This Surveillance Requirement requires a demonstration that a representative sample of reactor instrument line excess flow check valves (EFCVs) is OPERABLE by verifying that the valve actuates to the isolation position on a simulated instrument line break signal. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested in accordance with the Surveillance Frequency Control Program. In addition, the EFCVs in the sample are representative of the various plant configurations, models, sizes, and operating environments. This ensures that any potentially common problem with a specific type or application of EFCV is detected at the earliest possible time. This Surveillance Requirement provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during a postulated instrument line break event. Furthermore, any EFCV failures will be evaluated to determine if additional testing in the test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint. For some EFCVs, this Surveillance can be performed with the reactor at power.

CONTAINMENT SYSTEMS

BASES

3/4.6.4 VACUUM RELIEF

Vacuum relief valves are provided to equalize the pressure between the suppression chamber and drywell. This system will maintain the structural integrity of the primary containment under conditions of large differential pressures.

The vacuum breakers between the suppression chamber and the drywell must not be inoperable in the open position since this would allow bypassing of the suppression pool in case of an accident. Two pairs of valves are required to protect containment structural integrity. There are four pairs of valves (three to provide minimum redundancy) so that operation may continue for up to 72 hours or in accordance with the Risk Informed Completion Time Program with no more than two pairs of vacuum breakers inoperable in the closed position.

Each vacuum breaker valve's position indication system is of great enough sensitivity to ensure that the maximum steam bypass leakage coefficient of

$$\frac{A}{\sqrt{k}} = 0.05 \text{ ft}^2$$

for the vacuum relief system (assuming one valve fully open) will not be exceeded.

CONTAINMENT SYSTEMS

BASES

3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Enclosure and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a vacuum in the reactor enclosure secondary containment with the standby gas treatment system in accordance with the Surveillance Frequency Control Program, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the reactor enclosure recirculation system and the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting SITE BOUNDARY and Control Room radiation doses associated with containment leakage. The operation of these systems and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analysis. Provisions have been made to continuously purge the filter plenums with instrument air when the filters are not in use to prevent buildup of moisture on the adsorbers and the HEPA filters.

As a result of the Alternative Source Term (AST) project, secondary containment integrity of the refueling area is not required during certain conditions when handling irradiated fuel or during CORE ALTERATIONS and alignment of the Standby Gas Treatment System to the refueling area is not required. The control room dose analysis for the Fuel Handling Accident (FHA) is based on unfiltered releases from the South Stack and therefore, does not require the Standby Gas Treatment System to be aligned to the refueling area.

However, when handling RECENTLY IRRADIATED FUEL, secondary containment integrity of the refueling area is required and alignment of the Standby Gas Treatment System to the refueling area is required. The AST fuel handling analysis does not include an accident involving RECENTLY IRRADIATED FUEL or an accident involving draining the reactor vessel.

The Standby Gas Treatment System is required to be OPERABLE when handling irradiated fuel, handling RECENTLY IRRADIATED FUEL and during CORE ALTERATIONS. Fuel Handling Accident releases from the North Stack must be filtered through the Standby Gas Treatment System to maintain control room doses within regulatory limits. The OPERABILITY of the Standby Gas Treatment System assures that releases, if made through the North Stack, are filtered prior to release.

CONTAINMENT SYSTEMS

BASES

SECONDARY CONTAINMENT (Continued)

Surveillances 4.6.5.1.1.a and 4.6.5.1.2.a are each modified by a footnote (*) which states the surveillance is not required to be met for up to 4 hours if an analysis demonstrates that one standby gas treatment subsystem remains capable of establishing the required secondary containment vacuum. Use of the footnote is expected to be infrequent but may be necessitated by situations in which secondary containment vacuum may be less than the required containment vacuum, such as, but not limited to, wind gusts or failure or change of operating normal ventilation subsystems. These conditions do not indicate any change in the leak tightness of the secondary containment boundary. The analysis should consider the actual conditions (equipment configuration, temperature, atmospheric pressure, wind conditions, measured secondary containment vacuum, etc.) to determine whether, if an accident requiring secondary containment to be OPERABLE were to occur, one train of standby gas treatment could establish the assumed secondary containment vacuum within the time assumed in the accident analysis. If so, the surveillance may be considered met for a period up to 4 hours. The 4-hour limit is based on the expected short duration of the situations when the footnote would be applied.

Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 require verifying that one secondary containment personnel access door in each access opening is closed which provides adequate assurance that exfiltration from the secondary containment will not occur. An access opening contains at least one inner and one outer door. The intent is to not breach the secondary containment, which is achieved by maintaining the inner or outer personnel access door closed. Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 provide an allowance for brief, inadvertent, simultaneous openings of redundant secondary containment personnel access doors for normal entry and exit conditions.

Although the safety analyses assumes that the reactor enclosure secondary containment draw down time will take 930 seconds, these surveillance requirements specify a draw down time of 916 seconds. This 14 second difference is due to the diesel generator starting and sequence loading delays which is not part of this surveillance requirement.

The reactor enclosure secondary containment draw down time analyses assumes a starting point of 0.25 inch of vacuum water gauge and worst case SGTS dirty filter flow rate of 2800 cfm. The surveillance requirements satisfy this assumption by starting the drawdown from ambient conditions and connecting the adjacent reactor enclosure and refueling area to the SGTS to split the exhaust flow between the three zones and verifying a minimum flow rate of 2800 cfm from the test zone. This simulates the worst case flow alignment and verifies adequate flow is available to drawdown the test zone within the required time. The Technical Specification Surveillance Requirement 4.6.5.3.b.3 is intended to be a multi-zone air balance verification without isolating any test zone.

CONTAINMENT SYSTEMS

BASES

SECONDARY CONTAINMENT (Continued)

The SGTS fans are sized for three zones and therefore, when aligned to a single zone or two zones, will have excess capacity to more quickly drawdown the affected zones. There is no maximum flow limit to individual zones or pairs of zones and the air balance and drawdown time are verified when all three zones are connected to the SGTS.

The three zone air balance verification and drawdown test will be done after any major system alteration, which is any modification which will have an effect on the SGTS flowrate such that the ability of the SGTS to drawdown the reactor enclosure to greater than or equal to 0.25 inch of vacuum water gage in less than or equal to 916 seconds could be affected.

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CONTAINMENT SYSTEMS

BASES

3/4.6.5 SECONDARY CONTAINMENT (Continued)

The field tests for bypass leakage across the SGTS charcoal adsorber and HEPA filter banks are performed at a flow rate of $5764 \pm 10\%$ cfm. The laboratory analysis performed on the SGTS carbon samples will be tested at a velocity of 66 fpm based on the system residence time.

The SGTS filter train pressure drop is a function of air flow rate and filter conditions. Surveillance testing is performed using either the SGTS or drywell purge fans to provide operating convenience.

Each reactor enclosure secondary containment zone and refueling area secondary containment zone is tested independently to verify the design leak tightness. A design leak tightness of 2500 cfm or less for each reactor enclosure and 764 cfm or less for the refueling area at a 0.25 inch of vacuum water gage will ensure that containment integrity is maintained at an acceptable level if all zones are connected to the SGTS at the same time.

The Reactor Enclosure Secondary Containment Automatic Isolation Valves and Refueling Area Secondary Containment Automatic Isolation Valves can be found in the UFSAR.

The post-LOCA offsite dose analysis assumes a reactor enclosure secondary containment post-draw down leakage rate of 2500 cfm and certain post-accident X/Q values. While the post-accident X/Q values represent a statistical interpretation of historical meteorological data, the highest ground level wind speed which can be associated with these values is 7 mph (Pasquill-Gifford stability Class G for a ground level release). Therefore, the surveillance requirement assures that the reactor enclosure secondary containment is verified under meteorological conditions consistent with the assumptions utilized in the design basis analysis. Reactor Enclosure Secondary Containment leakage tests that are successfully performed at wind speeds in excess of 7 mph would also satisfy the leak rate surveillance requirements, since it shows compliance with more conservative test conditions.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

The primary containment atmospheric mixing system is provided to ensure adequate mixing of the containment atmosphere to prevent localized accumulations of hydrogen and oxygen from exceeding the lower flammability limit during post-LOCA conditions.

All nuclear reactors must be designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration <4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen <4.0 v/o works together with Drywell Hydrogen Mixing System to provide redundant and diverse methods to mitigate events that produce hydrogen.

CONTAINMENT SYSTEMS

BASES

3/4.6.6. PRIMARY CONTAINMENT ATMOSPHERE CONTROL (Continued)

If oxygen concentration is ≥ 4.0 v/o at any time while operating in OPERATIONAL CONDITION 1 or 2, oxygen concentration must be restored to < 4.0 v/o within 72 hours. The 72 hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o because of the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

The provision of Specification 3.0.4.c is applicable. This allowance permits entry into the applicable OPERATIONAL CONDITION(S) while relying on the Actions. This allowance is acceptable because inerting the primary containment prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup, after entering OPERATIONAL CONDITIONS 1 and 2, and deinerted as soon as possible in the plant shutdown. It is acceptable to intentionally enter the Action prior to a shutdown in order to begin deinerting the primary containment prior to exiting the Applicability.

If oxygen concentration cannot be restored to within the limit within the required Completion Time, the plant must be brought to a OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, power must be reduced to HOT SHUTDOWN within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

3/4.7 PLANT SYSTEMS

BASES

3/4.7.1 SERVICE WATER SYSTEMS - COMMON SYSTEMS

The OPERABILITY of the service water systems ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

The RHR and ESW systems are common to Units 1 and 2 and consist of two independent subsystems each with two pumps. One pump per subsystem (loop) is powered from a Unit 1 safeguard bus and the other pump is powered from a Unit 2 safeguard bus. In order to ensure adequate onsite power sources to the systems during a loss of offsite power event, the inoperability of these supplies are restricted in system ACTION statements.

RHRSW is a manually operated system used for core and containment heat removal. Each of two RHRSW subsystems has one heat exchanger per unit. Each RHRSW pump provides adequate cooling for one RHR heat exchanger. By limiting operation with less than three OPERABLE RHRSW pumps with OPERABLE Diesel Generators, each unit is ensured adequate heat removal capability for the design scenario of LOCA/LOOP on one unit and simultaneous safe shutdown of the other unit.

Each ESW pump provides adequate flow to the cooling loads in its associated loop. With only two divisions of power required for LOCA mitigation of one unit and one division of power required for safe shutdown of the other unit, one ESW pump provides sufficient capacity to fulfill design requirements. ESW pumps are automatically started upon start of the associated Diesel Generators. Therefore, the allowable out of service times for OPERABLE ESW pumps and their associated Diesel Generators is limited to ensure adequate cooling during a loss of offsite power event. Alternatively, the allowable out-of-service times can be determined in accordance with the Risk Informed Completion Time Program.

PLANT SYSTEMS

BASES

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM

The OPERABILITY of the control room emergency fresh air supply system ensures that the control room will remain habitable for occupants during and following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. Constant purge of the system at 1 cfm is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less Total Effective Dose Equivalent. This limitation is consistent with the requirements of 10 CFR Part 50.67, Accident Source Term.

Since the Control Room Emergency Fresh Air Supply System is not credited for filtration in OPERATIONAL CONDITIONS 4 and 5, applicability to 4 and 5 is only required to support the Chlorine and Toxic Gas design basis isolation requirements.

The Control Room Envelope (CRE) is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and other noncritical areas including adjacent support offices, toilet and utility rooms. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, ceiling, ducting, valves, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

In addition, The CREFAS System provides protection from smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 1). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 2).

In order for the CREFAS subsystems to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

PLANT SYSTEMS

BASES

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be initiated immediately to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

SR 4.7.2.2 verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem Total Effective Dose Equivalent and the CRE occupants are protected from hazardous chemicals and smoke. SR 4.7.2.2 verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Required Action 3.7.2.a.2 must be entered. Required Action 3.7.2.a.2.c allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 3) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 4). These compensatory measures may also be used as mitigating actions as required by Required Action 3.7.2.a.2.b. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 5). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

PLANT SYSTEMS

BASES

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

REFERENCES

1. UFSAR Section 6.4
2. UFSAR Section 9.5
3. Regulatory Guide 1.196
4. NEI 99-03, "Control Room Habitability Assessment Guidance," June 2001.
5. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the emergency core cooling system equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure exceeds 150 psig. This pressure is substantially below that for which low pressure core cooling systems can provide adequate core cooling. Management of gas voids is important to RCIC System OPERABILITY.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2, and 3 when reactor vessel pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period. Alternatively, out-of-service time can be determined in accordance with the Risk Informed Completion Time Program. A Note prohibits the application of Specification 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable RCIC subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that RCIC will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown.

Surveillance requirement 4.7.3.c.2 is normally met using reactor steam to verify the system will develop a flow greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine in the range of 150 to 165 psig. As an alternative, Auxiliary Steam can be used for the low pressure RCIC testing prior to reactor startup.

During plant startup, when the RCIC surveillance test is being performed, RCIC is required to be tested within 12 hours of changing modes. The intent of this requirement is to verify operability prior to reaching any significant power. If RCIC is not successfully demonstrated operable within the 12-hour period, the reactor steam dome pressure must be reduced to less than 150 psig within the following 72 hours. The intent of the action is to hold pressure at a point where sufficient steam is available to test the pump; it does not permit power ascension to continue.

PLANT SYSTEMS

BASES

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM (Continued)

The RCIC System flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RCIC System and may also prevent water hammer, pump cavitation, and pumping of noncondensable gas into the reactor vessel.

Selection of RCIC System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RCIC System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RCIC System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.7.3.a.2 is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

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PLANT SYSTEMS

BASES

3/4.7.4 DELETED

PLANT SYSTEMS

BASES

3/4.7.5 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e., sealed sources within radiation monitoring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

PLANT SYSTEMS

BASES

3/4 7.6 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

PLANT SYSTEMS

BASES

3/4 7.8 MAIN TURBINE BYPASS SYSTEM

The required OPERABILITY of the main turbine bypass system is consistent with the assumptions of the feedwater controller failure analysis in the cycle specific transient analysis.

The main turbine bypass system is required to be OPERABLE to limit peak pressure in the main steam lines and to maintain reactor pressure within acceptable limits during events that cause rapid pressurization such that the Safety Limit MCPR is not exceeded. With the main turbine bypass system inoperable, continued operation is based on the cycle specific transient analysis which has been performed for the feedwater controller failure, maximum demand with bypass failure.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety-related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criterion 17 of Appendix A to 10 CFR Part 50.

An offsite power source consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E emergency bus or buses. The determination of the OPERABILITY of an offsite source of power is dependent upon grid and plant factors that, when taken together, describe the design basis calculation requirements for voltage regulation. The combination of these factors ensures that the offsite source(s), which provide power to the plant emergency buses, will be fully capable of supporting the equipment required to achieve and maintain safe shutdown during postulated accidents and transients.

The plant factors consist of the status of the Startup Transformer (#10 and #20) load tap changers (LTCs), the status of the Safeguard Transformer (#101 and #201) load tap changers (LTCs), and the alignment of emergency buses on the Safeguard Buses (101-Bus and 201-Bus). For an offsite source to be considered operable, both of its respective LTCs (#10 AND #101 for the source to the 101-Bus, #20 AND #201 for the source to the 201-Bus) must be in service, and in automatic. For the third offsite source (from 66 kV System) to be considered operable, the connected Safeguard Transformer (#101 or #201) LTC must be in service and in automatic. There is a dependency between the alignment of the emergency buses and the allowable post contingency voltage drop percentage.

The grid factors consist of actual grid voltage levels (real time) and the post trip contingency voltage drop percentage value.

The minimum offsite source voltage levels are established by the voltage regulation calculation. The transmission system operator (TSO) will notify LGS when an agreed upon limit is approached.

The post trip contingency percentage voltage drop is a calculated value determined by the TSO that would occur as a result of the tripping of one of the Limerick generators. The TSO will notify LGS when an agreed upon limit is exceeded. The voltage regulation calculation establishes the acceptable percentage voltage drop based upon plant configuration; the acceptable value is dependent upon plant configuration.

Due to the 20 Source being derived from the tertiary of the 4A and 4B transformer, its operability is influenced by both the 230 kV system and the 500 kV system. The 10 Source operability is only influenced by the 230 kV system.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The anticipated post trip contingency voltage drop for the 66 kV Source (Transformers 8A/8B) is calculated to be less than the 230 kV and 500 kV systems. This is attributed to the electrical distance between the output of the Limerick generators and the input to the 8A/8B transformers. Additionally, the Unit Auxiliary Buses do not transfer to the 8A/8B transformers; this provides margin to the calculated post trip contingency voltage drop limit.

There are various means of hardening the 10 and 20 Sources to obtain additional margin to the post trip contingency voltage drop limits. These means include, but are not limited to, source alignment of the 4 kV buses, preventing transfer of 13 kV buses, limiting transfer of selected 13 kV loads, and operation with 13 kV buses on the offsite sources. The specific post trip contingency voltage drop percentage limits for these alignments are identified in the voltage regulation calculation, and controlled via plant procedures. There are also additional restrictions that can be applied to these limits in the event that an LTC is taken to manual, or if the bus alignment is outside the Two Source rule set.

LGS unit post trip contingency voltage drop percentage calculations are performed by the PJM Energy Management System (EMS). The PJM EMS consists of a primary and backup system. LGS will be notified if the real time contingency analysis capability of PJM is lost. Upon receipt of this notification, LGS is to request PJM to provide an assessment of the current condition of the grid based on the tools that PJM has available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and whether the current condition of the grid is bounded by the grid studies previously performed for LGS.

Based on specific design analysis, variations to any of these parameters can be determined, usually at the sacrifice of another parameter, based on plant conditions. Specifics regarding these variations must be controlled by plant procedures or by operability determinations, backed by specific design calculations.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least two of the onsite A.C. and the corresponding D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss-of-offsite power and single failure of the other onsite A.C. or D.C. source. At least two onsite A.C. and their corresponding D.C. power sources and distribution systems providing power for at least two ECCS divisions (1 Core Spray loop, 1 LPCI pump and 1 RHR pump in suppression pool cooling) are required for design basis accident mitigation as discussed in UFSAR Table 6.3-3.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Onsite A.C. operability requirements for common systems such as RHRSW and ESW are addressed in the appropriate system specification action statements.

A.C. Sources

As required by Specification 3.8.1.1, Action e, when one or more diesel generators are inoperable, there is an additional ACTION requirement to verify that all required systems, subsystems, trains, components, and devices, that depend on the remaining OPERABLE diesel generators as a source of emergency power, are also OPERABLE. The LPCI mode of the RHR system is considered a four train system, of which only two trains are required. The verification for LPCI is not required until two diesel generators are inoperable. This requirement is intended to provide assurance that a loss-of-offsite power event will not result in a complete loss of safety function of critical systems during the period when one or more of the diesel generators is inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

Specification 3.8.1.1, Action i, prohibits the application of Specification 3.0.4.b to an inoperable diesel generator. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable diesel generator subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

If it can be determined that the cause of the inoperable EDG does not exist on the remaining operable EDG(s), based on a common-mode evaluation, then the EDG start test (SR 4.8.1.1.2.a.4) does not have to be performed. If it cannot otherwise be determined that the cause of the initial inoperable EDG does not exist on the remaining EDG(s), then satisfactory performance of the start test suffices to provide assurance of continued operability of the remaining EDG(s). If the cause of the initial inoperability exists on the remaining operable EDG(s), the EDG(s) shall be declared inoperable upon discovery and the appropriate action statement for multiple inoperable EDGs shall be entered. In the event the inoperable EDG is restored to operable status prior to completing the EDG start test (SR 4.8.1.1.2.a.4) or common-mode failure evaluation as required in Specification 3.8.1.1, the plant corrective action program shall continue to evaluate the common-mode failure possibility. However, this continued evaluation is not subject to the time constraint imposed by the action statement. The provisions contained in the inoperable EDG action requirements that avoid unnecessary EDG testing are based on Generic Letter 93-05, "Line-Item Technical Specifications Improvement to Reduce Surveillance Requirements for Testing During Power Operation," dated September 27, 1993.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

The time, voltage, and frequency acceptance criteria specified for the EDG single largest post-accident load rejection test (SR 4.8.1.1.2.e.2) are derived from Regulatory Guide 1.9, Rev. 2, December 1979, recommendations. The test is acceptable if the EDG speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal, whichever is lower. This computes to be 66.5 Hz for the LGS EDGs. The RHR pump motor represents the single largest post-accident load. The 1.8 seconds specified is equal to 60% of the 3-second load sequence interval associated with sequencing the next load following the RHR pumps in response to an undervoltage on the electrical bus concurrent with a LOCA. This provides assurance that EDG frequency does not exceed predetermined limits and that frequency stability is sufficient to support proper load sequencing following a rejection of the largest single load.

D.C. Sources

With one division with one or two battery chargers inoperable (e.g., the voltage limit of 4.8.2.1.a.2 is not maintained), the ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Action a.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 18 hours, the battery will be restored to its fully charged condition (Action a.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 18 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 18 hours (Action a.2).

Action a.2 requires that the battery float current be verified for Divisions 1 and 2 as ≤ 2 amps, and for Divisions 3 and 4 as ≤ 1 amp. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 18 hour period the battery float current is not within limits this indicates there may be additional battery problems.

Action a.3 limits the restoration time for the inoperable battery charger to 7 days or in accordance with the Risk Informed Completion Time Program. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 days reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status. Alternatively, the allowable out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

With one or more cells in one or more batteries in one division < 2.07 V, the battery cell is degraded. Per Action b.1, within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (4.8.2.1.a.2) and of the overall battery state of charge by monitoring the battery float charge current (4.8.2.1.a.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, with one or more cells in one or more batteries < 2.07 V, continued operation is permitted for a limited period up to 24 hours.

Division 1 or 2 with float current > 2 amps, or Division 3 or 4 with float current > 1 amp, indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Per Action b.2, within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage.

Since Actions b.1 and b.2 only specify "perform," a failure of 4.8.2.1.a.1 or 4.8.2.1.a.2 acceptance criteria does not result in this Action not being met. However, if one of the Surveillance Requirements is failed the appropriate Action(s), depending on the cause of the failures, is also entered.

If the Action b.2 condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 18 hours is a reasonable time prior to declaring the battery inoperable.

With one or more batteries in one division with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits (i.e., greater than minimum level indication mark), the battery still retains sufficient capacity to perform the intended function. Per Action b.3, within 31 days the minimum established design limits for electrolyte level must be re-established.

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Action b.3 addresses this potential (as well as provisions in Specification 6.8.4.h, "Battery Monitoring and Maintenance Program"). Within 8 hours level is required to be restored to above the top of the plates. The Action requirement to verify that there is no leakage by visual inspection and the Specification 6.8.4.h item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the battery may have to be declared inoperable and the affected cell(s) replaced.

Per Action b.4, with one or more batteries in one division with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

Per Action b.5, with one or more batteries in more than one division with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that multiple divisions are involved. With multiple divisions involved, this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer restoration times specified for battery parameters on one division not within limits are therefore not appropriate, and the parameters must be restored to within limits on all but one division within 2 hours.

When any battery parameter is outside the allowances of Actions b.1, b.2, b.3, b.4, or b.5, sufficient capacity to supply the maximum expected load requirement is not ensured and a 2 hour restoration time is appropriate. Additionally, discovering one or more batteries in one division with one or more battery cells float voltage less than 2.07 V and float current greater than limits indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be restored within 2 hours.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

The surveillance requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," March 10, 1971, Regulatory Guide 1.137 "Fuel-Oil Systems for Standby Diesel Generators," Revision 1, October 1979 and Regulatory Guide 1.108,

ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

"Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977 except for paragraphs C.2.a(3), C.2.c(1), C.2.c(2), C.2.d(3) and C.2.d(4), and the periodic testing will be performed in accordance with the Surveillance Frequency Control Program. The exceptions to Regulatory Guide 1.108 allow for gradual loading of diesel generators during testing and decreased surveillance test frequencies (in response to Generic Letter 84-15). The single largest post-accident load on each diesel generator is the RHR pump.

The Surveillance Requirement for removal of accumulated water from the fuel oil storage tanks is for preventive maintenance. The presence of water does not necessarily represent failure of the Surveillance Requirement, provided the accumulated water is removed during performance of the Surveillance. Accumulated water in the fuel oil storage tanks constitutes a collection of water at a level that can be consistently and reliably measured. The minimum level at which accumulated water can be consistently and reliably measured in the fuel oil storage tank sump is 0.25 inches. Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of accumulated water from the fuel storage tanks once every (31) days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137.

The surveillance requirements for demonstrating the OPERABILITY of the units batteries are in accordance with the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications."

Verifying battery float current while on float charge (4.8.2.1.a.1) is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery.

Use of float current to determine the state of charge of the battery is consistent with IEEE Standard 450-1995.

This Surveillance Requirement (4.8.2.1.a.1) states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of 4.8.2.1.a.2. When this float voltage is not maintained, the Actions of 3.8.2.1 Action a., provides the necessary and appropriate verifications of the battery condition. Furthermore, the float current limits are established based on the float voltage range and is not directly applicable when this voltage is not maintained.

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ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Verifying, per 4.8.2.1.a.2, battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the minimum float voltage established by the battery manufacturer (2.20 Vpc, average, or 132 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years).

Surveillance Requirements 4.8.2.1.b.1 and 4.8.2.1.c require verification that the cell float voltages are equal to or greater than 2.07 V.

The limit specified in 4.8.2.1.b.2 for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability.

Surveillance Requirement 4.8.2.1.b.3 verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60 degrees Fahrenheit). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity.

Surveillance Requirement 4.8.2.1.d.1 verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32, the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

Surveillance Requirement 4.8.2.1.d.1 requires that each battery charger be capable of supplying the amps listed for the specified charger at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. This time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

A battery service test, per 4.8.2.1.d.2, is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in the UFSAR.

ELECTRICAL POWER SYSTEMS

BASES

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

A battery performance discharge test (4.8.2.1.e and f) is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage. Degradation (as used in 4.8.2.1.f) is indicated when the battery capacity drops more than 10% from its capacity on the previous performance test, or is below 90% of the manufacturer's rating.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying 4.8.2.1.e and 4.8.2.1.f; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of 4.8.2.1.d.2.

ELECTRICAL POWER SYSTEMS

BASES

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

The RPS Electric Power Monitoring System is provided to isolate the RPS bus from the RPS/UPS inverter or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus from unacceptable voltage and frequency conditions. The essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and valve isolation logic.

The Allowable Values are derived from equipment design limits, corrected for calibration and instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection and include allowances for instrumentation uncertainties, calibration tolerances, and instrument drift.

The Allowable Values for the instrument settings are based on the RPS providing power within the design ratings of the associated RPS components (e.g., RPS logic, scram solenoids). The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels.

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3/4.9 REFUELING OPERATIONS

BASES

3/4.9.1 REACTOR MODE SWITCH

Locking the OPERABLE reactor mode switch in the Shutdown or Refuel position, as specified, ensures that the restrictions on control rod withdrawal and refueling platform movement during the refueling operations are properly activated. These conditions reinforce the refueling procedures and reduce the probability of inadvertent criticality, damage to reactor internals or fuel assemblies, and exposure of personnel to excessive radioactivity.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of at least two source range monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core. The minimum count rate is not required when sixteen or fewer fuel assemblies are in the core. During a typical core reloading, two, three or four irradiated fuel assemblies will be loaded adjacent to each SRM to produce greater than the minimum required count rate. Loading sequences are selected to provide for a continuous multiplying medium to be established between the required operable SRMs and the location of the core alteration. This enhances the ability of the SRMs to respond to the loading of each fuel assembly. During a core unloading, the last fuel to be removed is that fuel adjacent to the SRMs.

3/4.9.3 CONTROL ROD POSITION

The requirement that all control rods be inserted during other CORE ALTERATIONS ensures that fuel will not be loaded into a cell without a control rod.

3/4.9.4 DECAY TIME

The minimum requirement for reactor subcriticality prior to fuel movement ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the accident analyses.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity condition during movement of fuel within the reactor pressure vessel.

REFUELING OPERATIONS

BASES (Continued)

3/4.9.6 REFUELING PLATFORM

The OPERABILITY requirements ensure that (1) the refueling platform will be used for handling control rods and fuel assemblies within the reactor pressure vessel, (2) each hoist has sufficient load capacity for handling fuel assemblies and control rods, (3) the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations, and (4) inadvertent criticality will not occur due to fuel being loaded into a unrodded cell.

Inadvertent criticality is prevented by the refueling interlocks that block unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn or withdrawal of a rod from the core while the grapple is over the core and loaded with fuel). The hoist loaded values identified in Sections 4.9.6.1b and 4.9.6.1c support the refueling interlock logic by ensuring that the hoist fuel loaded switches function with a load lighter than the weight of a single fuel assembly in water. Load values represent fuel (load) on the grapple. The values of 485 ± 50 pounds and $550 \pm 0, -115$ pounds are both less than the weight of a single fuel assembly in water attached to the grapple. These load values ensure that as soon as a fuel assembly is grappled and lifted, the refueling interlocks (control rod block and bridge motion interlock) are enforced as required. The hoist load weighing system is compensated for mast weight to ensure that lifting of components other than fuel assemblies (e.g., blade guides) do not cause inadvertent control rod blocks or bridge motion stops.

3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE POOL

The restriction on movement of loads in excess of the nominal weight of a fuel assembly and associated lifting device over other fuel assemblies in the storage pool ensures that in the event this load is dropped 1) the activity release will be limited to that contained in a single fuel assembly, and 2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

3/4.9.8 and 3/4.9.9 WATER LEVEL - REACTOR VESSEL and WATER LEVEL - SPENT FUEL STORAGE POOL

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

3/4.9.10 CONTROL ROD REMOVAL

These specifications ensure that maintenance or repair of control rods or control rod drives will be performed under conditions that limit the probability of inadvertent criticality. The requirements for simultaneous removal of more than one control rod are more stringent since the SHUTDOWN MARGIN specification provides for the core to remain subcritical with only one control rod fully withdrawn.

REFUELING OPERATIONS

BASES (Continued)

3/4.9.11. RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed by the RHR system to maintain adequate reactor coolant temperature.

RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR system provide decay heat removal. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System.

An OPERABLE RHR shutdown cooling subsystem consists of one (1) OPERABLE RHR pump, one (1) heat exchanger, and the associated piping and valves. The requirement for having one (1) RHR shutdown cooling subsystem OPERABLE ensures that 1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F, and 2) sufficient coolant circulation would be available through the reactor core to assure accurate temperature indication. Management of gas voids is important to RHR Shutdown Cooling Subsystem OPERABILITY.

The requirement to have two (2) RHR shutdown cooling subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange ensures that a single failure of the operating loop will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and 22 feet of water above the reactor vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR subsystem, adequate time is provided to initiate alternate methods capable of decay heat removal or emergency procedures to cool the core.

To meet the LCO of the two (2) subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. The two (2) subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Additionally, each shutdown cooling subsystem can provide the required decay heat removal capability; however, ensuring operability of the other shutdown cooling subsystem provides redundancy.

The required cooling capacity of an alternate method of decay heat removal should be ensured by verifying its capability to maintain or reduce reactor coolant temperature either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

REFUELING OPERATIONS

BASES

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION (Continued)

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensable gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to placing the system in operation when in OPCON 5. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System that is aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. An RHR Shutdown Cooling sub-system that is already in operation at the time of entry into the APPLICABILITY is OPERABLE. For an idle RHR Shutdown Cooling subsystem, the surveillance is met through the performance of the operating procedures that place the RHR Shutdown Cooling subsystem in service.

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Action "a", additional actions are required to minimize any potential fission product release to the environment. This includes ensuring Refueling Floor Secondary Containment is OPERABLE; one (1) Standby Gas Treatment subsystem is OPERABLE; and Secondary Containment isolation capability (i.e., one (1) Secondary Containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactive releases. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

If no RHR subsystem is in operation, an alternate method of coolant circulation is required to be established within one (1) hour. The Completion Time is modified such that one (1) hour is applicable separately for each occurrence involving a loss of coolant circulation.

3/4.10 SPECIAL TEST EXCEPTIONS

BASES

3.4.10.1 PRIMARY CONTAINMENT INTEGRITY

The requirement for PRIMARY CONTAINMENT INTEGRITY is not applicable during the period when open vessel tests are being performed during the low power PHYSICS TESTS.

3/4.10.2 ROD WORTH MINIMIZER

In order to perform the tests required in the technical specifications it is necessary to bypass the sequence restraints on control rod movement. The additional surveillance requirements ensure that the specifications on heat generation rates and shutdown margin requirements are not exceeded during the period when these tests are being performed and that individual rod worths do not exceed the values assumed in the safety analysis.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations with the vessel head removed requires additional restrictions in order to ensure that criticality does not occur. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

3/4.10.5 OXYGEN CONCENTRATION

Relief from the oxygen concentration specifications is necessary in order to provide access to the primary containment during the initial startup and testing phase of operation. Without this access the startup and test program could be restricted and delayed.

3/4.10.6 TRAINING STARTUPS

This special test exception permits training startups to be performed with the reactor vessel depressurized at low THERMAL POWER and temperature while controlling RCS temperature with one RHR subsystem aligned in the shutdown cooling mode in order to minimize contaminated water discharge to the radioactive waste disposal system.

3/4.10.7 RESERVED - CURRENTLY NOT USED

3/4.10 SPECIAL TEST EXCEPTIONS

BASES

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

This special test exception permits certain reactor coolant pressure tests to be performed in OPERATIONAL CONDITION 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) or plant temperature control capabilities during these tests require the pressure testing at temperatures greater than 200°F (normally corresponding to OPERATIONAL CONDITION 3). The additionally imposed OPERATIONAL CONDITION 3 requirements for SECONDARY CONTAINMENT INTEGRITY provide conservatism in response to an operational event.

Invoking the requirement for Refueling Area Secondary Containment Integrity along with the requirement for Reactor Enclosure Secondary Containment Integrity applies the requirements for Reactor Enclosure Secondary Containment Integrity to an extended area encompassing Zones 1 and 3. Core alterations and fuel handling are prohibited in this secondary containment configuration. Drawdown and inleakage testing performed for the combined zone system alignment shall be considered adequate to demonstrate integrity of the combined zones.

Inservice hydrostatic testing and inservice leak pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code are performed prior to the reactor going critical after a refueling outage. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.6, Reactor Coolant System Pressure/Temperature Limits. These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence. With increased reactor fluence over time, the minimum allowable vessel temperature increases at a given pressure.

3/4.11 RADIOACTIVE EFFLUENTS

BASES

3/4.11.1.1 and 3/4.11.1.2 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

RADIOACTIVE EFFLUENTS

BASES

3/4.11.1.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.11.1.4 LIQUID HOLDUP TANKS

The tanks listed in this specification include all those outdoor radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than 10 times the limits of 10 CFR Part 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

3/4.11.2.1 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

RADIOACTIVE EFFLUENTS

BASES

3/4.11.2.2 through 3/4.11.2.4 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

RADIOACTIVE EFFLUENTS

BASES

3/4.11.2.5 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

RADIOACTIVE EFFLUENTS

BASES

3/4.11.2.6 MAIN CONDENSER

Restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50.

3/4 11.2.7, 3/4 11.3, and 3/4 11.4 (Deleted) - INFORMATION FROM THESE SECTIONS
RELOCATED TO THE ODCM OR PCP.

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3/4.12 RADIOLOGICAL ENVIRONMENTAL MONITORING

BASES

Section 3/4.12 (Deleted)

THE INFORMATION FROM THIS SECTION HAS BEEN
RELOCATED TO THE ODCM. BASES PAGE B 3/4 12-2
HAS BEEN INTENTIONALLY OMITTED.

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