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REMOVE MANUAL TABLE OF CONTENTS DATE: 03/31/2005

ADD MANUAL TABLE OF CONTENTS DATE: 04/18/2005

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT 3.0
REMOVE: REV:0

ADD: REV: 1

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT 3.3.3.1
REMOVE: REV:0

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ADD: REV: 1

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT 3.3.3.2
REMOVE: REV:0

ADD: REV: 1

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT 3.4.6
REMOVE: REV:0

ADD: REV: 1

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT 3.4.7
REMOVE: REV:0

ADD: REV: 1

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT 3.4.8
REMOVE: REV:0

ADD: REV: 1

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT 3.5.1
REMOVE: REV:0

ADD: REV: 1

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT 3.5.3
REMOVE: REV:0

ADD: REV: 1

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT 3.6.3.1
REMOVE: REV:0

ADD: REV: 1

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT 3.6.3.2
REMOVE: REV:0

ADD: REV: 1

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT 3.8.1
REMOVE: REV:1

ADD: REV: 2

CATEGORY: DOCUMENTS TYPE: TSB2
ID: TEXT LOES
ADD: REV: 57

REMOVE: REV:57

ADD: REV: 58

CATEGORY: DOCUMENTS TYPE: TSB2

ID: TEXT TOC
REMOVE: REV:6

ADD: REV: 7

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Manual Name: TSB2

Manual Title: TECHNICAL SPECIFICATIONS BASES UNIT 2 MANUAL

Table Of Contents

Issue Date: 04/18/2005

Manual Name: TSB2

Manual Title: TECHNICAL SPECIFICATIONS BASES UNIT 2 MANUAL

TEXT 3.1.7 0 11/18/2002

Title: REACTIVITY CONTROL SYSTEMS STANDBY LIQUID CONTROL (SLC) SYSTEM

TEXT 3.1.8 0 11/18/2002

Title: REACTIVITY CONTROL SYSTEMS SCRAM DISCHARGE VOLUME (SDV) VENT AND DRAIN VALVES

TEXT 3.2.1 1 03/24/2005

Title: POWER DISTRIBUTION LIMITS AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

TEXT 3.2.2 1 03/24/2005

Title: POWER DISTRIBUTION LIMITS MINIMUM CRITICAL POWER RATIO (MCPR)

TEXT 3.2.3 0 11/18/2002

Title: POWER DISTRIBUTION LIMITS LINEAR HEAT GENERATION RATE (LHGR)

TEXT 3.2.4 0 11/18/2002

Title: POWER DISTRIBUTION LIMITS AVERAGE POWER RANGE MONITOR (APRM) GAIN AND SETPOINTS

TEXT 3.3.1.1 1 03/01/2005

Title: INSTRUMENTATION REACTOR PROTECTION SYSTEM (RPS) INSTRUMENTATION

TEXT 3.3.1.2 0 11/18/2002

Title: INSTRUMENTATION SOURCE RANGE MONITOR (SRM) INSTRUMENTATION

TEXT 3.3.1.3 0 11/22/2004

Title: OPRM INSTRUMENTATION

TEXT 3.3.2.1 1 02/17/2005

Title: INSTRUMENTATION CONTROL ROD BLOCK INSTRUMENTATION

TEXT 3.3.2.2 0 11/18/2002

Title: INSTRUMENTATION FEEDWATER - MAIN TURBINE HIGH WATER LEVEL TRIP INSTRUMENTATION

TEXT 3.3.3.1 1 04/18/2005

Title: INSTRUMENTATION POST ACCIDENT MONITORING (PAM) INSTRUMENTATION

Manual Name: TSB2

Manual Title: TECHNICAL SPECIFICATIONS BASES UNIT 2 MANUAL

TEXT 3.3.3.2 1 04/18/2005

Title: INSTRUMENTATION REMOTE SHUTDOWN SYSTEM

TEXT 3.3.4.1 0 11/18/2002

Title: INSTRUMENTATION END OF CYCLE RECIRCULATION PUMP TRIP (EOC-RPT) INSTRUMENTATION

TEXT 3.3.4.2 0 11/18/2002

Title: INSTRUMENTATION ANTICIPATED TRANSIENT WITHOUT SCRAM RECIRCULATION PUMP TRIP (ATWS-RPT) INSTRUMENTATION

TEXT 3.3.5.1 2 01/24/2005

Title: INSTRUMENTATION EMERGENCY CORE COOLING SYSTEM (ECCS) INSTRUMENTATION

TEXT 3.3.5.2 0 11/18/2002

Title: INSTRUMENTATION REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM INSTRUMENTATION

TEXT 3.3.6.1 1 11/09/2004

Title: INSTRUMENTATION PRIMARY CONTAINMENT ISOLATION INSTRUMENTATION

TEXT 3.3.6.2 1 11/09/2004

Title: INSTRUMENTATION SECONDARY CONTAINMENT ISOLATION INSTRUMENTATION

TEXT 3.3.7.1 0 11/18/2002

Title: INSTRUMENTATION CONTROL ROOM EMERGENCY OUTSIDE AIR SUPPLY (CREOAS) SYSTEM INSTRUMENTATION

TEXT 3.3.8.1 1 09/02/2004

Title: INSTRUMENTATION LOSS OF POWER (LOP) INSTRUMENTATION

TEXT 3.3.8.2 0 11/18/2002

Title: INSTRUMENTATION REACTOR PROTECTION SYSTEM (RPS) ELECTRIC POWER MONITORING

TEXT 3.4.1 2 11/22/2004

Title: REACTOR COOLANT SYSTEM (RCS) RECIRCULATION LOOPS OPERATING

TEXT 3.4.2 0 11/18/2002

Title: REACTOR COOLANT SYSTEM (RCS) JET PUMPS

Manual Name: TSB2

Manual Title: TECHNICAL SPECIFICATIONS BASES UNIT 2 MANUAL

TEXT 3.4.3 0 11/18/2002

Title: REACTOR COOLANT SYSTEM (RCS) SAFETY/RELIEF VALVES (S/RVS)

TEXT 3.4.4 0 11/18/2002

Title: REACTOR COOLANT SYSTEM (RCS) RCS OPERATIONAL LEAKAGE

TEXT 3.4.5 0 11/18/2002

Title: REACTOR COOLANT SYSTEM (RCS) RCS PRESSURE ISOLATION VALVE (PIV) LEAKAGE

TEXT 3.4.6 1 04/18/2005

Title: REACTOR COOLANT SYSTEM (RCS) RCS LEAKAGE DETECTION INSTRUMENTATION

TEXT 3.4.7 1 04/18/2005

Title: REACTOR COOLANT SYSTEM (RCS) RCS SPECIFIC ACTIVITY

TEXT 3.4.8 1 04/18/2005

Title: REACTOR COOLANT SYSTEM (RCS) RESIDUAL HEAT REMOVAL (RHR) SHUTDOWN COOLING SYSTEM - HOT SHUTDOWN

TEXT 3.4.9 0 11/18/2002

Title: REACTOR COOLANT SYSTEM (RCS) RESIDUAL HEAT REMOVAL (RHR) SHUTDOWN COOLING SYSTEM - COLD SHUTDOWN

TEXT 3.4.10 0 11/18/2002

Title: REACTOR COOLANT SYSTEM (RCS) RCS PRESSURE AND TEMPERATURE (P/T) LIMITS

TEXT 3.4.11 0 11/18/2002

Title: REACTOR COOLANT SYSTEM (RCS) REACTOR STEAM DOME PRESSURE

TEXT 3.5.1 1 04/18/2005

Title: EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM ECCS - OPERATING

TEXT 3.5.2 0 11/18/2002

Title: EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM ECCS - SHUTDOWN

TEXT 3.5.3 1 04/18/2005

Title: EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM RCIC SYSTEM

Manual Name: TSB2

Manual Title: TECHNICAL SPECIFICATIONS BASES UNIT 2 MANUAL

TEXT 3.6.1.1 0 11/18/2002

Title: CONTAINMENT SYSTEMS PRIMARY CONTAINMENT

TEXT 3.6.1.2 0 11/18/2002

Title: CONTAINMENT SYSTEMS PRIMARY CONTAINMENT AIR LOCK

TEXT 3.6.1.3 0 11/18/2002

Title: CONTAINMENT SYSTEMS PRIMARY CONTAINMENT ISOLATION VALVES (PCIVS)

TEXT 3.6.1.4 0 11/18/2002

Title: CONTAINMENT SYSTEMS CONTAINMENT PRESSURE

TEXT 3.6.1.5 0 11/18/2002

Title: CONTAINMENT SYSTEMS DRYWELL AIR TEMPERATURE

TEXT 3.6.1.6 0 11/18/2002

Title: CONTAINMENT SYSTEMS SUPPRESSION CHAMBER-TO-DRYWELL VACUUM BREAKERS

TEXT 3.6.2.1 0 11/18/2002

Title: CONTAINMENT SYSTEMS SUPPRESSION POOL AVERAGE TEMPERATURE

TEXT 3.6.2.2 0 11/18/2002

Title: CONTAINMENT SYSTEMS SUPPRESSION POOL WATER LEVEL

TEXT 3.6.2.3 0 11/18/2002

Title: CONTAINMENT SYSTEMS RESIDUAL HEAT REMOVAL (RHR) SUPPRESSION POOL COOLING

TEXT 3.6.2.4 0 11/18/2002

Title: CONTAINMENT SYSTEMS RESIDUAL HEAT REMOVAL (RHR) SUPPRESSION POOL SPRAY

TEXT 3.6.3.1 1 04/18/2005

Title: CONTAINMENT SYSTEMS PRIMARY CONTAINMENT HYDROGEN RECOMBINERS

TEXT 3.6.3.2 1 04/18/2005

Title: CONTAINMENT SYSTEMS DRYWELL AIR FLOW SYSTEM

Manual Name: TSB2

Manual Title: TECHNICAL SPECIFICATIONS BASES UNIT 2 MANUAL

TEXT 3.6.3.3 0 11/18/2002
Title: CONTAINMENT SYSTEMS PRIMARY CONTAINMENT OXYGEN CONCENTRATION

TEXT 3.6.4.1 2 03/01/2005
Title: CONTAINMENT SYSTEMS SECONDARY CONTAINMENT

TEXT 3.6.4.2 2 01/03/2005
Title: CONTAINMENT SYSTEMS SECONDARY CONTAINMENT ISOLATION VALVES (SCIVS)

TEXT 3.6.4.3 2 11/09/2004
Title: CONTAINMENT SYSTEMS STANDBY GAS TREATMENT (SGT) SYSTEM

TEXT 3.7.1 0 11/18/2002
Title: PLANT SYSTEMS RESIDUAL HEAT REMOVAL SERVICE WATER (RHRSW) SYSTEM AND THE ULTIMATE HEAT SINK (UHS)

TEXT 3.7.2 1 11/09/2004
Title: PLANT SYSTEMS EMERGENCY SERVICE WATER (ESW) SYSTEM

TEXT 3.7.3 0 11/18/2002
Title: PLANT SYSTEMS CONTROL ROOM EMERGENCY OUTSIDE AIR SUPPLY (CREOAS) SYSTEM

TEXT 3.7.4 0 11/18/2002
Title: PLANT SYSTEMS CONTROL ROOM FLOOR COOLING SYSTEM

TEXT 3.7.5 0 11/18/2002
Title: PLANT SYSTEMS MAIN CONDENSER OFFGAS

TEXT 3.7.6 1 01/17/2005
Title: PLANT SYSTEMS MAIN TURBINE BYPASS SYSTEM

TEXT 3.7.7 0 11/18/2002
Title: PLANT SYSTEMS SPENT FUEL STORAGE POOL WATER LEVEL

TEXT 3.8.1 2 04/18/2005
Title: ELECTRICAL POWER SYSTEMS AC SOURCES - OPERATING

Manual Name: TSB2

Manual Title: TECHNICAL SPECIFICATIONS BASES UNIT 2 MANUAL

TEXT 3.8.2 0 11/18/2002

Title: ELECTRICAL POWER SYSTEMS AC SOURCES - SHUTDOWN

TEXT 3.8.3 0 11/18/2002

Title: ELECTRICAL POWER SYSTEMS DIESEL FUEL OIL, LUBE OIL, AND STARTING AIR

TEXT 3.8.4 0 11/18/2002

Title: ELECTRICAL POWER SYSTEMS DC SOURCES - OPERATING

TEXT 3.8.5 0 11/18/2002

Title: ELECTRICAL POWER SYSTEMS DC SOURCES - SHUTDOWN

TEXT 3.8.6 0 11/18/2002

Title: ELECTRICAL POWER SYSTEMS BATTERY CELL PARAMETERS

TEXT 3.8.7 0 11/18/2002

Title: ELECTRICAL POWER SYSTEMS DISTRIBUTION SYSTEMS - OPERATING

TEXT 3.8.8 0 11/18/2002

Title: ELECTRICAL POWER SYSTEMS DISTRIBUTION SYSTEMS - SHUTDOWN

TEXT 3.9.1 0 11/18/2002

Title: REFUELING OPERATIONS REFUELING EQUIPMENT INTERLOCKS

TEXT 3.9.2 0 11/18/2002

Title: REFUELING OPERATIONS REFUEL POSITION ONE-ROD-OUT INTERLOCK

TEXT 3.9.3 0 11/18/2002

Title: REFUELING OPERATIONS CONTROL ROD POSITION

TEXT 3.9.4 0 11/18/2002

Title: REFUELING OPERATIONS CONTROL ROD POSITION INDICATION

TEXT 3.9.5 0 11/18/2002

Title: REFUELING OPERATIONS CONTROL ROD OPERABILITY - REFUELING

Manual Name: TSB2

Manual Title: TECHNICAL SPECIFICATIONS BASES UNIT 2 MANUAL

TEXT 3.9.7 0 11/18/2002

Title: REFUELING OPERATIONS RESIDUAL HEAT REMOVAL (RHR) - HIGH WATER LEVEL

TEXT 3.9.8 0 11/18/2002

Title: REFUELING OPERATIONS RESIDUAL HEAT REMOVAL (RHR) - LOW WATER LEVEL

TEXT 3.10.1 0 11/18/2002

Title: SPECIAL OPERATIONS INSERVICE LEAK AND HYDROSTATIC TESTING OPERATION

TEXT 3.10.2 0 11/18/2002

Title: SPECIAL OPERATIONS REACTOR MODE SWITCH INTERLOCK TESTING

TEXT 3.10.3 0 11/18/2002

Title: SPECIAL OPERATIONS SINGLE CONTROL ROD WITHDRAWAL - HOT SHUTDOWN

TEXT 3.10.4 0 11/18/2002

Title: SPECIAL OPERATIONS SINGLE CONTROL ROD WITHDRAWAL - COLD SHUTDOWN

TEXT 3.10.5 0 11/18/2002

Title: SPECIAL OPERATIONS SINGLE CONTROL ROD DRIVE (CRD) REMOVAL - REFUELING

TEXT 3.10.6 0 11/18/2002

Title: SPECIAL OPERATIONS MULTIPLE CONTROL ROD WITHDRAWAL - REFUELING

TEXT 3.10.7 1 03/24/2005

Title: SPECIAL OPERATIONS CONTROL ROD TESTING - OPERATING

TEXT 3.10.8 1 03/24/2005

Title: SPECIAL OPERATIONS SHUTDOWN MARGIN (SDM) TEST - REFUELING

(continued)

(continued)

TSB2 TOC.doc
3/18/05

Section	Title	Revision
TOC	Table of Contents	7
B 2.0	SAFETY LIMITS BASES	
	Page TS / B 2.0-1	1
	Page TS / B 2.0-2	2
	Page TS / B 2.0-3	3
	Page TS / B 2.0-4	4
	Page TS / B 2.0-5	1
	Pages B 2.0-6 through B 2.0-8	0
B 3.0	LCO AND SR APPLICABILITY BASES	
	Pages B 3.0-1 through B 3.0-4	0
	Pages TS / B 3.0-5 through TS / B 3.0-7	1
	Pages TS / B 3.0-8 through TS / B 3.0-9	2
	Pages TS / B 3.0-10 through TS / B 3.0-12	1
	Pages TS / B 3.0-13 through TS / B 3.0-15	2
	Pages TS / B 3.0-16 and TS / B 3.0-17	0
B 3.1	REACTIVITY CONTROL BASES	
	Pages B 3.1-1 through B 3.1-4	0
	Page TS / B 3.1-5	1
	Pages TS / B 3.1-6 and TS / B 3.1-7	2
	Pages B 3.1-8 through B 3.1-27	0
	Page TS / B 3.1-28	2
	Pages B 3.1-29 through B 3.1-33	0
	Pages TS / B 3.1.34 through TS / B 3.1-36	1
	Page TS / B 3.1-37	2
	Page TS / B 3.1-38	2
	Pages B 3.1-39 through B 3.1-51	0
B 3.2	POWER DISTRIBUTION LIMITS BASES	
	Pages TS / B 3.2-1 and TS / B 3.2-2	1
	Page TS / B 3.2-3	2
	Page TS / B 3.2-4	1
	Pages TS / B 3.2-5 and TS / B 3.2-6	3
	Page TS / B 3.2-7	2
	Pages TS / B 3.2-8 and TS / B 3.2-9	3
	Pages TS / B 3.2-10 through TS / B 3.2-19	1
B 3.3	INSTRUMENTATION	
	Pages TS / B 3.3-1 through TS / B 3.3-7	1
	Pages TS / B 3.3-8 through TS / B 3.3-11	2
	Pages TS / B 3.3-12 through TS / B 3.3-27	1
	Pages TS / B 3.3-28 through TS / B 3.3-30	2
	Page TS / B 3.3-31	1
	Pages TS / B 3.3-32 and TS / B 3.3-33	2
	Pages TS / B 3.3-34 through TS / B 3.3-43	1

Section	Title	Revision
	Pages TS / B 3.3-43a though TS / B 3.3-43i	0
	Pages TS / B 3.3-44 through TS / B 3.3-54	2
	Pages B 3.3-55 through B 3.3-63	0
	Pages TS / B 3.3-64 and TS / B 3.3-65	2
	Page TS / B 3.3-66	4
	Page TS / B 3.3-67	3
	Page TS / B 3.3-68	4
	Pages TS / B 3.3-69 and TS / B 3.3-70	3
	Pages TS / B 3.3-71	3
	Pages TS / B 3.3-72 through TS / B 3.3-75	2
	Page TS / B 3.3-75a	4
	Pages TS / B 3.3-75b through TS / B 3.3-75c	3
	Pages B 3.3-76 through TS / B 3.3-77	0
	Page TS / B 3.3-78	1
	Pages B 3.3-79 through B 3.3-91	0
	Pages TS / B 3.3-92 through TS / B 3.3-103	1
	Page TS / B 3.3-104	2
	Pages TS / B 3.3-105 and TS / B 3.3-106	1
	Page TS / B 3.3-107	2
	Page TS / B 3.3-108	1
	Page TS / B 3.3-109	2
	Pages TS / B 3.3-110 through TS / B 3.3-115	1
	Pages TS / B 3.3-116 through TS / B 3.3-118	2
	Pages TS / B 3.3-119 through TS / B 3.3-120	1
	Pages TS / B 3.3-121 and TS / B 3.3-122	2
	Page TS / B 3.3-123	1
	Page TS / B 3.3-124	2
	Page TS / B 3.3-124a	0
	Page TS / B 3.3-125	1
	Page TS / B 3.3-126	2
	Page TS / B 3.3-127	3
	Page TS / B 3.3-128	2
	Pages TS / B 3.3-129 through TS / B 3.3-131	1
	Page TS / B 3.3-132	2
	Pages TS / B 3.3-133 and TS / B 3.3-134	1
	Pages B 3.3-135 through B 3.3-137	0
	Page TS / B 3.3-138	1
	Pages B 3.3-139 through B 3.3-149	0
	Pages TS/ B 3.3-150 through TS / B 3.3-162	1
	Page TS / B 3.3-163	2
	Pages TS / B 3.3-164 through TS / B 3.3-177	1
	Page TS / B 3.3-178	2
	Page TS / B 3.3-179	3
	Page TS / B 3.3-179a	2
	Page TS / B 3.3-180	1
	Page TS / B 3.3-181	2
	Pages TS / B 3.3-182 through TS / B 3.3-186	1

Section	Title	Revision
	Pages TS / B 3.3-187 and TS / B 3.3-188	2
	Pages TS / B 3.3-189 through TS / B 3.3-191	1
	Pages B 3.3-192 through B 3.3-205	0
	Page TS / B 3.3-206	1
	Pages B 3.3-207 through B 3.3-220	0
B 3.4	REACTOR COOLANT SYSTEM BASES	
	Pages TS / B 3.4-1 and TS / B 3.4-2	1
	Pages TS / B 3.4-3 through TS / B 3.4-9	3
	Pages B 3.4-10 through B 3.4-14	0
	Page TS / B 3.4-15	1
	Pages TS / B 3.4-16 and TS / B 3.4-17	2
	Page TS / B 3.4-18	1
	Pages B 3.4-19 through B 3.4-28	0
	Page TS / B 3.4-29	1
	Pages B 3.4-30 through B 3.3-31	0
	Page TS / B 3.4-32	1
	Pages B 3.4-33 through B 3.4-36	0
	Page TS / B 3.4-37	1
	Pages B 3.4-38 through B 3.4-40	0
	Page TS / B 3.4-41	1
	Pages B 3.4-42 through B 3.4-48	0
	Page TS / B 3.4-49	2
	Page TS / B 3.4-50	1
	Page TS / B 3.4-51	2
	Pages TS / B 3.4-52 and TS / B 3.4-53	1
	Pages TS / B 3.4-54 and TS / B 3.4-55	2
	Pages TS / B 3.4-56 through TS / B 3.4-60	1
B 3.5	ECCS AND RCIC BASES	
	Pages TS / B 3.5-1 and TS / B 3.5-2	1
	Page TS / B 3.5-3	2
	Page TS / B 3.5-4	1
	Pages TS / B 3.5-5 and TS / B 3.5-6	2
	Pages TS / B 3.5-7 through TS / B 3.5-10	1
	Page TS / B 3.5-11	2
	Pages TS / B 3.5-12 through TS / B 3.5-14	1
	Pages TS / B 3.5-15 through TS / B.3.5-17	2
	Page TS / B 3.18	1
	Pages B 3.5-19 through B 3.5-24	0
	Page TS / B 3.5-25	1
	Pages TS / B 3.5-26 and TS / B 3.5-27	1
	Pages B 3.5-28 through B 3.5-31	0

TSB2 LOES
4/14/05

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.7 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).

LCO 3.0.2

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that:

a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and

b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering

(continued)

BASES

LCO 3.0.2 (continued)

ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.10, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Additionally, if intentional entry into actions would result in redundant equipment being inoperable, alternatives should be used instead. Doing so limits the time both subsystems/divisions of a safety function are inoperable and limits the time other conditions exist which may result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable and the ACTIONS Condition(s) are entered.

(continued)

BASES (continued)

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit 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 reach lower MODES 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 capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, Completion Times.

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BASES

LCO 3.0.3 (continued)

A unit shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met.

b. A Condition exists for which the Required Actions have now been performed.

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

The time limits of Specification 3.0.3 allow 37 hours for the unit to be in MODE 4 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 4, or other applicable MODE, is not reduced. For example, if MODE 2 is reached in 2 hours, then the time allowed for reaching MODE 3 is the next 11 hours, because the total time for reaching MODE 3 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, and 3, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 4 and 5 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, or 3) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.7, "Spent Fuel Storage Pool Water Level." LCO 3.7.7 has an Applicability of "During movement of irradiated fuel

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BASES

LCO 3.0.3 (continued)

assemblies in the spent fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.7 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.7 of "Suspend movement of irradiated fuel assemblies in the spent fuel storage pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE 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 LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE 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 MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

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 to be assessed and managed. The risk assessment, for the

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BASES

LCO 3.0.4 (continued)

purposes of LCO 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 MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 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 MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 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 LCO 3.0.4.b allowance is prohibited. The LCOs governing these systems and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

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BASES

LCO 3.0.4 (continued)

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS 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 ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., [Containment Air Temperature, Containment Pressure, MCPR, Moderator Temperature Coefficient]) 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 MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES 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 MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2 or MODE 3, MODE 2 to MODE 3, and MODE 3 to MODE 4.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and Required Actions until the Condition is resolved, until the LCO 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 SR 3.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 3.0.1 or

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BASES

LCO 3.0.4 (continued)

SR 3.0.4 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 LCO.

LCO 3.0.5

LCO 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 LCO 3.0.2 (e.g., to not comply with the applicable Required 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 absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the required testing.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition 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.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This

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BASES

LCO 3.0.6 (continued)

exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO 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 LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions. When a support system is inoperable and there is an LCO 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' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCOs' Conditions and Required 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 Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.11, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 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 Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross division checks to identify a loss of safety function for those support systems that support safety systems are required. The cross division check verifies that the supported systems of the redundant OPERABLE support

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BASES

LCO 3.0.6 (continued

system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO 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 or concurrent loss of emergency diesel generators. Since operation is 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. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable diesel generator(s) provide the necessary restriction for cross train inoperabilities. This explicit cross train verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperability of a normal or emergency electrical power source (refer to the definition of OPERABILITY).

When a loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of safety function is solely due to a single TS 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 LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately addresses the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Special Operations LCOs in Section 3.10 allow specified TS requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

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BASES

LCO 3.0.7 (continued)

The Applicability of a Special Operations LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Special Operations LCOs is optional. A special operation may be performed either under the provisions of the appropriate Special Operations LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Special Operations LCO, the requirements of the Special Operations LCO shall be followed. When a Special Operations LCO requires another LCO to be met, only the requirements of the LCO statement are required to be met regardless of that LCO's Applicability (i.e., should the requirements of this other LCO not be met, the ACTIONS of the Special Operations LCO apply, not the ACTIONS of the other LCO). However, there are instances where the Special Operations LCO ACTIONS may direct the other LCOs' ACTIONS be met. The Surveillances of the other LCO are not required to be met, unless specified in the Special Operations LCO. If conditions exist such that the Applicability of any other LCO is met, all the other LCO's requirements (ACTIONS and SRs) are required to be met concurrent with the requirements of the Special Operations LCO.

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs	SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO 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 Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO.

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 a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a Special Operations LCO are only applicable when the Special Operations LCO 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 MODE or other specified condition.

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BASES

SR 3.0.1 (continued)

Surveillances, including Surveillances invoked by Required Actions, 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 SR 3.0.2, prior to returning equipment to OPERABLE status.

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 SR 3.0.2. Post maintenance testing may not be possible in the current MODE 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 a MODE 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 > 800 psi. However, if other appropriate testing is satisfactorily completed and the scram time testing of SR 3.1.4.3 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 800 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.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic

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BASES

SR 3.0.2 (continued)

performance of the Required Action on a "once per..." interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications.

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

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

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met.

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BASES

SR 3.0.3 (continued)

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

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

When a Surveillance with a Frequency based not on the time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix j, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

SR 3.0.3 provides a time limit for, and allowances for the performance of Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency 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. The risk impact should be managed through the program in place to

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BASES

SR 3.0.3 (continued)

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 Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES 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 MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to Surveillance not being met in accordance with LCO 3.0.4.

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SR 3.0.4 (continued)

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified 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 SR 3.0.1, which states that Surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 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 Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES 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 MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2 or MODE 3, MODE 2 to MODE 3, and MODE 3 to MODE 4.

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCOs Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately,
the Surveillance may be stated in the form of a Note, as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

B 3.3 INSTRUMENTATION

B 3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

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

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

APPLICABLE SAFETY ANALYSES

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

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

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

- Determine whether systems important to safety are performing their intended functions;

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BASES

APPLICABLE SAFETY ANALYSES (continued)

- Determine the potential for causing a gross breach of the barriers to radioactivity release;
- Determine whether a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and for an estimate of the magnitude of any impending threat.

The plant specific Regulatory Guide 1.97 Analysis (Ref. 2 and 3) documents the process that identified Type A and Category I, non-Type A, variables.

Accident monitoring instrumentation that satisfies the definition of Type A in Regulatory Guide 1.97 meets Criterion 3 of the NRC Policy Statement. (Ref. 4) Category I, non-Type A, instrumentation is retained in Technical Specifications (TS) because they are intended to assist operators in minimizing the consequences of accidents. Therefore, these Category I variables are important for reducing public risk.

LCO

LCO 3.3.3.1 requires two OPERABLE channels for all but one Function to ensure that no single failure prevents the operators from being presented with the information necessary to determine the status of the plant and to bring the plant to, and maintain it in, a safe condition following that accident.

Furthermore, provision of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

The exception to the two channel requirement is primary containment isolation valve (PCIV) position. In this case, the important information is the status of the primary containment penetrations. The LCO requires one position indicator for each active PCIV. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of passive valve or via system boundary

(continued)

BASES

LCO (continued)

status. If a normally active PCIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

The following list is a discussion of the specified instrument Functions listed in Table 3.3.3.1-1 in the accompanying LCO. Table B3.3.3.1-1 provides a listing of the instruments that are used to meet the operability requirements for the specific functions.

1. Reactor Steam Dome Pressure

Reactor steam dome pressure is a Type A, Category 1, variable provided to support monitoring of Reactor Coolant System (RCS) integrity and to verify operation of the Emergency Core Cooling Systems (ECCS). Two independent pressure channels, consisting of three wide range control room indicators and one wide range control room recorder per channel with a range of 0 psig to 1500 psig, monitor pressure. The wide range recorders are the primary method of indication available for use by the operators during an accident, therefore, the PAM Specification deals specifically with this portion of the instrument channel.

2. Reactor Vessel Water Level

Reactor vessel water level is a Type A, Category 1, variable provided to support monitoring of core cooling and to verify operation of the ECCS. A combination of three different level instrument ranges, with two independent channels each, monitor Reactor Vessel Water Level. The extended range instrumentation measures from -150 inches to 180 inches and outputs to three control room level indicators per channel. The wide range instrumentation measures from -150 inches to 60 inches and outputs to one control room recorder and three control room indicators per channel. The fuel zone range instrumentation measures from -310 inches to -110 inches and outputs to a control room recorder (one channel) and a control room indicator (one channel). These three ranges of instruments combine to provide level indication from the bottom of the Core to above the main steam line. The wide range level recorders, the fuel zone level indicator and level recorder, and one inner ring extended range level indicator per channel are the primary method of indication available for use by the operator during an accident, therefore the PAM

(continued)

BASES

LCO

2. Reactor Vessel Water Level (continued)

Specification deals specifically with this portion of the instrument channel.

3. Suppression Chamber Water Level

Suppression chamber water level is a Type A, Category 1, variable provided to detect a breach in the reactor coolant pressure boundary (RCPB). This variable is also used to verify and provide long term surveillance of ECCS function. A combination of two different level instrument ranges, with two independent channels each, monitor Suppression chamber water level. The wide range instrumentation measures from the ECCS suction lines to approximately the top of the chamber and outputs to one control room recorder per channel. The wide range recorders are the primary method of indication available for use by the operator during an accident, therefore the PAM Specification deals specifically with this portion of the instrument channel.

4. Primary Containment Pressure

Primary Containment pressure is a Type A, Category 1, variable provided to detect a breach of the RCPB and to verify ECCS functions that operate to maintain RCS integrity. A combination of two different pressure instrument ranges, with two independent channels each, monitor primary containment pressure. The LOCA range measures from -15 psig to 65 psig and outputs to one control room recorder per channel. The accident range measures from 0 psig to 250 psig and outputs to one control room recorder per channel (same recorders as the LOCA range). The recorders (both ranges) are the primary method of indication available for use by the operator during an accident, therefore the PAM Specification deals specifically with this portion of the instrument channel.

5. Primary Containment High Radiation

Primary containment area radiation (high range) is provided to monitor the potential of significant radiation releases

(continued)

BASES

LCO

5. Primary Containment High Radiation (continued)

and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Two independent channels, which output to one control room recorder per channel with a range of 10^0 to $1X10^8$ R/hr, monitor radiation. The PAM Specification deals specifically with this portion of the instrument channel.

6. Primary Containment Isolation Valve (PCIV) Position

PCIV position is provided for verification of containment integrity. In the case of PCIV position, the important information is the isolation status of the containment penetration. The LCO requires a channel of valve position indication in the control room to be OPERABLE for an active PCIV in a containment penetration flow path, i.e., two total channels of PCIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active PCIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration via indicated status of the active valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration flow path is isolated, position indication for the PCIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration flow path is not required to be OPERABLE. Those valves which require position indication are specified in Table B 3.6.1.3-1. Furthermore, the loss of position indication does not necessarily result in the PCIV being inoperable.

The PCIV position PAM instrumentation consists of position switches unique to PCIVs, associated wiring and control room indicating lamps (not necessarily unique to a PCIV) for active PCIVs (check valves and manual valves are not required to have position indication). Therefore, the PAM Specification deals specifically with these instrument channels.

(continued)

BASES

LCO (continued)

7. Neutron Flux

Wide range neutron flux is a Category I variable provided to verify reactor shutdown. The Neutron Monitoring System Average Power Range Monitors (APRM) which consist of 6 channels that output to four control room recorders (one for channels A and C, one for channels B and D, one for channel E and one for channel F) provide reliable neutron flux measurement from 0% to 125% of full power. The PAM function for neutron flux is satisfied by any one channel of APRMs in each division (channels A,C, E comprise division one, channels B,D,F comprise division two). The PAM Specification deals specifically with this portion of the instrument channel.

The Neutron Monitoring System (NMS) was evaluated against the criteria established in General Electric NEDO-31558A to ensure its acceptability for post-accident monitoring. NEDO-31558A provides alternate criteria for the NMS to meet the post-accident monitoring guidance of Regulatory Guide 1.97. Based on the evaluation, the NMS was found to meet the criteria established in NEDO-31558A. The APRM sub-function of the NMS is used to provide the Neutron Flux monitoring identified in TS 3.3.3.1 (Ref. 5 and 6).

8. Containment Hydrogen and Oxygen Analyzers

The drywell and suppression chamber hydrogen and oxygen concentrations are Type A, Category 1, variables. Two independent gas analyzers monitor hydrogen and oxygen concentration to detect unsafe combustible gas levels in primary containment. The analyzers are capable of determining hydrogen concentration in the range of 0 to 30% by volume and oxygen concentration in the range of 0 to 10% by volume, and each provide control room indication and output to a control room recorder. Each gas analyzer must be capable of sampling either the drywell or the suppression chamber. The recorders are the primary method of indication available for use by the operator during an accident, therefore the PAM Specification deals specifically with this portion of the instrument channel. The gas analyzer piping is provided with heat tracing to reduce the buildup of condensation in the system. H2O2 Analyzers can be considered OPERABLE for accident monitoring (TS 3.3.3.1) for up to 100 days with their heat tracing INOPERABLE.

(continued)

BASES

LCO (continued)

9. Drywell Atmosphere Temperature

Drywell atmosphere temperature is a Category I variable provided to verify RCS and containment integrity and to verify the effectiveness of ECCS actions taken to prevent containment breach. Two independent temperature channels, consisting of two control room recorders per channel with a range of 40 to 440 degrees F, monitor temperature. The PAM Specification deals specifically with the inner ring temperature recorder portion of the instrument channel.

10. Suppression Chamber Water Temperature

Suppression Chamber water temperature is a Type A, Category 1, variable provided to detect a condition that could potentially lead to containment breach and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression chamber water temperature instrumentation allows operators to detect trends in suppression chamber water temperature in sufficient time to take action to prevent steam quenching vibrations in the suppression pool. Two channels are required to be OPERABLE. Each channel consists of eight sensors of which a minimum of four sensors (one sensor in each quadrant) must be OPERABLE to consider a channel OPERABLE. The outputs for the temperature sensors are displayed on two independent indicators in the control room and recorded on the monitoring units located in the control room on a back panel. The temperature indicators are the primary method of indication available for use by the operator during an accident, therefore the PAM Specification deals specifically with this portion of the instrument channel.

APPLICABILITY

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

(continued)

BASES (continued)

ACTIONS

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

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channels, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of action in accordance with Specification 5.6.7, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions.

(continued)

BASES

ACTIONS

B.1 (continued)

This action is appropriate in lieu of a shutdown requirement because alternative actions are identified before the written report is submitted to the NRC, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1

When one or more Functions have two required channels that are inoperable (i.e., two channels inoperable in the same Function), one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.3.1-1. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C, as applicable, and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1

For the majority of Functions in Table 3.3.3.1-1, if any Required Action and associated Completion Time of Condition C are not met, the plant must be brought to a MODE in which the LCO not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions

(continued)

BASES

ACTIONS

E.1 (continued)

from full power conditions in an orderly manner and without challenging plant systems.

F.1

Since alternate means of monitoring primary containment area radiation have been developed and tested, the Required Action is not to shut down the plant, but rather to follow the directions of Specification 5.6.7. These alternate means will be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

The following SRs apply to each PAM instrumentation Function in Table 3.3.3.1-1.

SR 3.3.3.1.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel against a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria which are determined by the plant staff based on an investigation of a combination of the channel instrument uncertainties, may be used to support this

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1.1 (continued)

parameter comparison and include indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit, and does not necessarily indicate the channel is Inoperable.

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

SR 3.3.3.1.2 and SR 3.3.3.1.3

A CHANNEL CALIBRATION is performed every 92 days for the containment Hydrogen and Oxygen Analyzers or 24 months for the other Functions except for the PCIV Position Function. The PCIV Position Function is adequately demonstrated by the Remote Position Indication performed in accordance with 5.5.6, "Inservice Testing Program". CHANNEL CALIBRATION verifies that the channel responds to measured parameter with the necessary range and accuracy, and does not include alarms.

The CHANNEL CALIBRATION for the Containment High Radiation instruments shall consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr and a one point calibration check of the detector below 10 R/hr with an installed or portable gamma source.

The CHANNEL CALIBRATION for the hydrogen analyzers, use a sample gas containing: a) Nominal zero volume percent hydrogen, balance nitrogen and b) Nominal thirty volume percent hydrogen, balance nitrogen.

The Frequency is based on operating experience and for the 24 month Frequency consistency with the industry refueling cycles.

(continued)

BASES (continued)

REFERENCES

1. Regulatory Guide 1.97 Rev. 2, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," February 6, 1985

2. Nuclear Regulatory Commission Letter A. Schwencer to N. Curtis, Emergency Response Capability, Conformance to R.G. 1.97, Rev. 2, dated February 6, 1985.

3. PP&L Letter (PLA-2222), N. Curtis to A. Schwencer, dated May 31, 1984.

4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 32193)

5. NEDO-31558A, BWROG Topical Report, Position on NRC Reg. Guide 1.97, Revision 3 Requirements for Post Accident Neutron Monitoring System (NMS).

6. Nuclear Regulatory Commission Letter from C. Poslusny to R.G. Byram dated July 3, 1996.

TABLE B 3.3.3.1-1
Post Accident Instruments
(Page 1 of 3)

Instrument/Variable	Element	Transmitter	Recorder	Indicator
1. Reactor Steam Dome Pressure	N/A	PT-24201A	LP/PR-24201A (blue pen)*	PI-24202A PI-24202A1 PI-24204A
	N/A	PT-24201B	LR/PR-24201B (blue pen)*	PI-24202B (left side) PI-24202B1 (left side) PI-24204B (left side)
2. Reactor Vessel Water Level	N/A	LT-24201A (Wide Range)	LR/PR-24201A (red pen)*	LI-24201A (left side) LI-24201A1 (left side) LI-24203A (left side)
	N/A	LT-24201B (Wide Range)	LR/PR-24201B (red pen)*	LI-24201B (left side) LI-24201B1 (left side) LI-24203B (left side)
	N/A	LT-24203A (Extended Range)	N/A	LI-24201A (right side)*(1) LI-24201A1 (right side) LI-24203A (right side)
	N/A	LT-24203B (Extended Range)	N/A	LI-24201B (right side)*(1) LI-24201B1 (right side) LI-24203B (right side)
	N/A	LT-24202A (Fuel Zone Range)	LR-24202 (red pen)*	N/A
	N/A	LT-24202B (Fuel Zone Range)	N/A	LI-24205B*
3. Suppression Chamber Water Level	N/A	LT-25776A (Wide Range)	LR-25776A (red pen)*	N/A
	N/A	LT-25776B (Wide Range)	LR-25776B (red pen)*	N/A
	N/A	LT-25775A (Narrow Range)	LR-25776A (blue pen)	LI-25775A
	N/A	LT-25775B (Narrow Range)	LR-25776B (blue pen)	LI-25775B

TABLE B 3.3.3.1-1
Post Accident Instruments
(Page 2 of 3)

Instrument/Variable	Element	Transmitter	Recorder	Indicator
4. Primary Containment Pressure	N/A	PT-25709A (0 to 250 psig)	PR-25710A (blue pen)*	N/A
	N/A	PT-25709B (0 to 250 psig)	PR-25710B (blue pen)*	N/A
	N/A	PT-25710A (-15 to 65 psig)	PR-25710A (red pen)*	N/A
	N/A	PT-25710B (-15 to 65 psig)	PR-25710B (red pen)*	N/A
5. Primary Containment High Radiation	RE-25720A	RITS-25720A	RR-25720A*	N/A
	RE-25720B	RITS-25720B	RR-25720B*	N/A
6. PCIV Position	See Technical Specification Bases Table B 3.6.1.3-1 for PCIV that require position indication to be OPERABLE			
7. Neutron Flux	N/A	APRM-A	NR-C51-2R603A (red pen)*	N/A
	N/A	APRM-B	NR-C51-2R603B (red pen)*	N/A
	N/A	APRM-C	NR-C51-2R603A (blue pen)*	N/A
	N/A	APRM-D	NR-C51-2R603B (blue pen)*	N/A
	N/A	APRM-E	NR-C51-2R603C (red pen)*	N/A
	N/A	APRM-F	NR-C51-2R603D (red pen)*	N/A
8. Containment Oxygen and Hydrogen Analyzer	AE-25745A (Hydrogen)	AT-25745A	AR-25746A (red pen)* AR-25746A (blue pen)*	N/A
	AE-25745B (Hydrogen)	AT-25745B	AR-25746B (red pen)* AR-25746B (blue pen)*	N/A
	AE-25746A (Oxygen)	AT-25746A	AR-25746A (green pen)*	N/A
	AE-25746B (Oxygen)	AT-25746B	AR-25746B (green pen)*	N/A

TABLE B 3.3.3.1-1
Post Accident Instruments
(Page 3 of 3)

Instrument/Variable	Element	Transmitter	Recorder	Indicator
9. Drywell Atmosphere Temperature	TE-25790A	TT-25790A	TR-25790A1 (red pen)* TR-25790A (point # 1)	N/A
	TE-257908	TT-25790B	TR-25790B1 (red pen)* TR-25790B (point # 1)	N/A
10. Suppression Chamber Water Temperature	TE-25753 TE-25755 TE-25757 TE-25759 TE-25763 TE-25765 TE-25767 TE-25769	TX-25751	N/A	TIAH-25751* TI-25751
	TE-25752 TE-25754 TE-25758 TE-25760 TE-25762 TE-25766 TE-25768 TE-25770	TX-25752	N/A	TIAH-25752* TI-25752

* Indicates that the instrument (and associated components in the instrument channel) is considered as instrument channel surveillance acceptance criteria.

(1) In the case of the inner ring indicators for extended range level, it is recommended that LI-24201A and LI-24201B be used as acceptance criteria, however LI-24201A1, LI-24201B1, LI-24203A. or LI-24203B may be used in their place provided that surveillance requirements are satisfied. Only one set of these instruments needs to be OPERABLE.

B 3.3 INSTRUMENTATION

B 3.3.3.2 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the plant in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility of the control room becoming inaccessible. A safe shutdown condition is defined as MODE 3. With the plant in MODE 3, the Reactor Core Isolation Cooling (RCIC) System, the safety/relief valves, and the Residual Heat Removal Shutdown Cooling System can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the RCIC and the ability to operate shutdown cooling from outside the control room allow extended operation in MODE 3.

In the event that the control room becomes inaccessible, the operators can establish control at the remote shutdown panel and place and maintain the plant in MODE 3. Not all controls and necessary transfer switches are located at the remote shutdown panel. Some controls will have to be operated locally at the switchgear, motor control panels, or other local stations. The plant automatically reaches MODE 3 following a plant shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the Remote Shutdown System control and instrumentation Functions ensures that there is sufficient information available on selected plant parameters to place and maintain the plant in MODE 3 should the control room become inaccessible.

APPLICABLE SAFETY ANALYSES

The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a design capability to promptly shut down the reactor to MODE 3, including the necessary instrumentation and controls, to maintain the plant in a safe condition in MODE 3.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The criteria governing the design and the specific system requirements of the Remote Shutdown System are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1).

The Remote Shutdown System is considered an important contributor to reducing the risk of accidents; as such, it has been retained in the Technical Specifications (TS) as indicated in the NRC Policy Statement. (Ref. 3)

LCO

The Remote Shutdown System LCO provides the requirements for the OPERABILITY of the instrumentation and controls necessary to place and maintain the plant in MODE 3 from a location other than the control room.

The controls, instrumentation, and transfer switches are those required in Table 3.3.3.2-1.

The Remote Shutdown System is OPERABLE if all instrument and control channels needed to support the remote shutdown function are OPERABLE. In some cases, the required information or control capability is available from several alternate sources. In these cases, the Remote Shutdown System is OPERABLE as long as one channel of any of the alternate information or control sources for each Function is OPERABLE.

The Remote Shutdown System instruments and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure that the instruments and control circuits will be OPERABLE if plant conditions require that the Remote Shutdown System be placed in operation.

APPLICABILITY

The Remote Shutdown System LCO is applicable in MODES 1 and 2. This is required so that the plant can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODES 3, 4, and 5. In these MODES, the plant is already subcritical and in a condition of reduced Reactor Coolant System energy. Under these conditions, considerable time is available to restore

(continued)

BASES

APPLICABILITY (continued)

necessary instrument control Functions if control room instruments or control becomes unavailable. Consequently, the TS do not require OPERABILITY in MODES 3, 4, and 5.

ACTIONS

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

<u>A.1</u>

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System is inoperable. This includes any Function listed in Table 3.3.3.2-1, as well as the control and transfer switches.

The Required Action is to restore the Function (both divisions, if applicable) to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

(continued)

BASES

ACTIONS (continued)

B.1

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

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Remote Shutdown System Instrument Function are located in the SRs column of Table 3.3.3.2-1.

SR 3.3.3.2.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria which are determined by the plant staff based on an investigation of a combination of the channel instrument uncertainties may be used to support this parameter comparison and include indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit, and does not necessarily indicate the channel is Inoperable. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency is based upon plant operating experience that demonstrates channel failure is rare.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.2.2

SR 3.3.3.2.2 verifies each required Remote Shutdown System transfer switch and control circuit performs the intended function. This verification is performed from the remote shutdown panel. Operation of the equipment from the remote shutdown panel is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the plant can be placed and maintained in MODE 3 from the remote shutdown panel and the local control stations. Operating experience demonstrates that Remote Shutdown System control channels usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.3.2.3

CHANNEL CALIBRATION verifies that the channel responds to measured parameter values with the necessary range and accuracy.

The 24 month Frequency is based upon operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.
2. FSAR 7.4.1.4.
3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 32193)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of 10 CFR 50, Appendix A (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (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. The Bases for LCO 3.4.4, "RCS Operational LEAKAGE," discuss the limits on RCS LEAKAGE rates.

Systems for separating the LEAKAGE of an identified source from an unidentified source 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 two or three independently monitored variables, such as sump level changes and drywell gaseous and particulate radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain sump monitoring system which consists of two drywell floor drain sump level Channels. Both Channels are required to be Operable to satisfy the LCO.

The drywell floor drain sump monitoring system monitors the LEAKAGE collected in the floor drain sump. This unidentified LEAKAGE consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, the Closed Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain tank.

The level of each drywell sump is recorded by continuous pen recorders located in the Main Control Room. The change in

(continued)

BASES

BACKGROUND (continued)

sump level per unit time determines the leak rate and is calculated from the recorder.

The floor drain sump level indicators have switches that start and stop the sump pumps when required. If the sump fills to the high high level setpoint, an alarm sounds in the control room.

The primary containment air monitoring systems continuously monitor the primary containment atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room. The primary containment atmosphere particulate and gaseous radioactivity monitoring systems are not capable of quantifying LEAKAGE rates. These monitors provide an alternate means of leak detection to that supplied by the sump level monitors, and although they cannot ensure detection of a 1 gpm leak in 1 hour in all cases, they provide a diverse means of leak detection (Ref. 3).

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. 4 and 5). Each of the leakage detection systems inside the drywell is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Ref. 6). 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 (Ref. 7).

LCO

The drywell floor drain sump monitoring system is required to quantify the unidentified LEAKAGE from the RCS. Thus, for the system to be considered OPERABLE, the system must be capable of measuring reactor coolant leakage. The other monitoring systems provide early alarms to the operators so closer examination of other detection systems will be made

(continued)

BASES

LCO (continued)

to determine the extent of any corrective action that may be required. With the leakage detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.

APPLICABILITY

In MODES 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.4. This Applicability is consistent with that for LCO 3.4.4.

ACTIONS

A.1

With the drywell floor drain sump monitoring system inoperable, the primary containment atmospheric activity monitor will provide indication of changes in leakage.

With the drywell floor drain sump monitoring system inoperable, operation may continue for 30 days. However, RCS unidentified and total LEAKAGE is still required to be determined every 12 hours (SR 3.4.4.1). The 30 day Completion Time of Required Action A.1 is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

B.1 and B.2

With both gaseous and particulate primary containment atmospheric monitoring channels 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 at least one of the required monitors.

The 12 hour interval provides periodic information that is adequate to detect LEAKAGE. The 30 day Completion Time for

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

restoration recognizes that at least one other form of leakage detection is available.

The Required Actions are modified by a Note that states that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when both the gaseous and particulate primary containment atmospheric monitoring channels are inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

C.1 and C.2

If any Required Action of Condition A or B cannot be met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the actions in an orderly manner and without challenging plant systems.

D.1

With all required monitors inoperable, no required automatic means of monitoring LEAKAGE are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

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. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

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 Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

SR 3.4.6.3

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. The Frequency of 24 months is a typical refueling cycle and considers channel reliability.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. FSAR, Section 5.2.5.1.2.
4. GEAP-5620, April 1968.
5. NUREG-75/067, October 1975.
6. FSAR, Section 5.2.5.4.
7. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Specific Activity

BASES

BACKGROUND

During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the reactor coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the reactor coolant can plate out in the RCS, and, at times, an accumulation will break away to spike the normal level of radioactivity. The release of coolant during a Design Basis Accident (DBA) could send radioactive materials into the environment.

Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure that in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 100 (Ref. 1).

This LCO contains iodine specific activity limits. The iodine isotopic activities per gram of reactor coolant are expressed in terms of a DOSE EQUIVALENT I-131. The allowable levels are intended to limit the 2 hour radiation dose to an individual at the site boundary to a small fraction of the 10 CFR 100 limit.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving radioactive material in the primary coolant are presented in the FSAR (Ref. 2). The specific activity in the reactor coolant (the source term) is an initial condition for evaluation of the consequences of an accident due to a main steam line break (MSLB) outside containment. No fuel damage is postulated in the MSLB accident, and the release of radioactive material to the environment is assumed to end when the main steam isolation valves (MSIVs) close completely.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

This MSLB release forms the basis for determining offsite doses (Ref. 2). The limits on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses at the site boundary, resulting from an MSLB outside containment during steady state operation, will not exceed 10% of the dose guidelines of 10 CFR 100.

The limits on specific activity are values from a parametric evaluation of typical site locations. These limits are conservative because the evaluation considered more restrictive parameters than for a specific site, such as the location of the site boundary and the meteorological conditions of the site.

RCS specific activity satisfies Criterion 2 of the NRC Policy Statement (Ref. 3).

LCO

The specific iodine activity is limited to ≤ 0.2 μCi/gm DOSE EQUIVALENT I-131. This limit ensures the source term assumed in the safety analysis for the MSLB is not exceeded, so any release of radioactivity to the environment during an MSLB is less than a small fraction of the 10 CFR 100 limits.

APPLICABILITY

In MODE 1, and MODES 2 and 3 with any main steam line not isolated, limits on the primary coolant radioactivity are applicable since there is an escape path for release of radioactive material from the primary coolant to the environment in the event of an MSLB outside of primary containment.

In MODES 2 and 3 with the main steam lines isolated, such limits do not apply since an escape path does not exist. In MODES 4 and 5, no limits are required since the reactor is not pressurized and the potential for leakage is reduced.

BASES (continued)

ACTIONS

A.1 and A.2

When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is ≤ 4.0 μCi/gm, samples must be analyzed for DOSE EQUIVALENT I-131 at least once every 4 hours. In addition, the specific activity must be restored to the LCO limit within 48 hours. The Completion Time of once every 4 hours is based on the time needed to take and analyze a sample. The 48 hour Completion Time to restore the activity level provides a reasonable time for temporary coolant activity increases (iodine spikes or crud bursts) to be cleaned up with the normal processing systems.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1, B.2.1, B.2.2.1, and B.2.2.2

If the DOSE EQUIVALENT I-131 cannot be restored to ≤ 0.2 μCi/gm within 48 hours, or if at any time it is > 4.0 μCi/gm, it must be determined at least once every 4 hours and all the main steam lines must be isolated within 12 hours. Isolating the main steam lines precludes the possibility of releasing radioactive material to the environment in an amount that is more than a small fraction of the requirements of 10 CFR 100 during a postulated MSLB accident.

Alternatively, the plant can be placed in MODE 3 within 12 hours and in MODE 4 within 36 hours. This option is provided for those instances when isolation of main steam lines is not desired (e.g., due to the decay heat loads). In MODE 4, the requirements of the LCO are no longer applicable.

(continued)

BASES

ACTIONS

B.1, B.2.1, B.2.2.1, and B.2.2.2 (continued)

The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 12 hour Completion Time is reasonable, based on operating experience, to isolate the main steam lines in an orderly manner and without challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for placing the unit in MODES 3 and 4 are reasonable, based on operating experience, to achieve the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This Surveillance is performed to ensure iodine remains within limit during normal operation. The 7 day Frequency is adequate to trend changes in the iodine activity level.

This SR is modified by a Note that requires this Surveillance to be performed only in MODE 1 because the level of fission products generated in other MODES is much less.

REFERENCES

1. 10 CFR 100.11, 1973.
2. FSAR, Section 15.6.4.
3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown

BASES

BACKGROUND

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 to reduce the temperature of the reactor coolant to ≤ 200°F. This decay heat removal is in preparation for performing refueling or maintenance operations, or for keeping the reactor in the Hot Shutdown condition.

The shutdown cooling function of the RHR System provides decay heat removal and is manually controlled. Each RHR loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. 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 (LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System").

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. Although the RHR shutdown cooling subsystem does not meet a specific criterion of the NRC Policy Statement (Ref. 1), it was identified in the NRC Policy Statement as a significant contributor to risk reduction. Therefore, the RHR Shutdown Cooling System is retained as a Technical Specification.

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and when no recirculation pump is in operation, one shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, and the associated piping and valves. The two subsystems have a common suction source and are allowed to have a common heat exchanger and

(continued)

BASES

LCO (continued)

common discharge piping. Thus, to meet the LCO, both pumps in one loop or one pump in each of the two 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. Each 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. In MODE 3, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain or 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.

Note 1 permits both RHR shutdown cooling subsystems to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for the performance of Surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODE 3 with reactor steam dome pressure below the RHR cut in permissive pressure (i.e., the actual pressure at which the interlock resets) the RHR System may be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut in permissive pressure is typically accomplished by condensing

(continued)

BASES

APPLICABILITY (continued)

the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS—Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODES 4 and 5 are discussed in LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level."

ACTIONS

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

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

With one required RHR shutdown cooling subsystem inoperable for decay heat removal, except as permitted by LCO Note 2, the inoperable subsystem must be restored to OPERABLE status

(continued)

BASES

ACTIONS

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

without delay. In this condition, the remaining OPERABLE subsystem can provide the necessary decay heat removal. The overall reliability is reduced, however, because a single failure in the OPERABLE subsystem could result in reduced RHR shutdown cooling capability. Therefore, an alternate method of decay heat removal must be provided.

With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities.

The required cooling capacity of the alternate method must be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Spent Fuel Pool Cooling System and the Reactor Water Cleanup System.

However, due to the potentially reduced reliability of the alternate methods of decay heat removal, it is also required to reduce the reactor coolant temperature to the point where MODE 4 is entered.

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

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or recirculation pump must be restored without delay.

Until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function

(continued)

BASES

ACTIONS

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

and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

This Surveillance is modified by a Note allowing sufficient time to align the RHR System for shutdown cooling operation after the pressure interlock that isolates the system resets, or for placing a recirculation pump in operation. The Note takes exception to the requirements of the Surveillance being met (i.e., forced coolant circulation is not required for this initial 2 hour period), which also allows entry into the Applicability of this Specification in accordance with SR 3.0.4 since the Surveillance will not be "not met" at the time of entry into the Applicability.

REFERENCES

1. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.1 ECCS—Operating

BASES

BACKGROUND

The ECCS is designed, in conjunction with the primary and secondary containment, to limit the release of radioactive materials to the environment following a loss of coolant accident (LOCA). The ECCS uses two independent methods (flooding and spraying) to cool the core during a LOCA. The ECCS network consists of the High Pressure Coolant Injection (HPCI) System, the Core Spray (CS) System, the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System, and the Automatic Depressurization System (ADS). The suppression pool provides the required source of water for the ECCS. Although no credit is taken in the safety analyses for the condensate storage tank (CST), it is capable of providing a source of water for the HPCI and CS systems.

On receipt of an initiation signal, ECCS pumps automatically start; simultaneously, the system aligns and the pumps inject water, taken either from the CST or suppression pool, into the Reactor Coolant System (RCS) as RCS pressure is overcome by the discharge pressure of the ECCS pumps. Although the system is initiated, ADS action is delayed, allowing the operator to interrupt the timed sequence if the system is not needed. The HPCI pump discharge pressure quickly exceeds that of the RCS, and the pump injects coolant into the vessel to cool the core. If the break is small, the HPCI System will maintain coolant inventory as well as vessel level while the RCS is still pressurized. If HPCI fails, it is backed up by ADS in combination with LPCI and CS. In this event absent operator action, the ADS timed sequence would time out and open the selected safety/relief valves (S/RVs) depressurizing the RCS, thus allowing the LPCI and CS to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure initially drops rapidly and the LPCI and CS cool the core.

Water from the break returns to the suppression pool where it is used again and again. Water in the suppression pool is circulated through a heat exchanger cooled by the RHR Service Water System. Depending on the location and size of the break, portions of the ECCS may be ineffective;

(continued)

BASES

BACKGROUND (continued)

however, the overall design is effective in cooling the core regardless of the size or location of the piping break. Although no credit is taken in the safety analysis for the RCIC System, it performs a similar function as HPCI, but has reduced makeup capability. Nevertheless, it will maintain inventory and cool the core while the RCS is still pressurized following a reactor pressure vessel (RPV) isolation.

All ECCS subsystems are designed to ensure that no single active component failure will prevent automatic initiation and successful operation of the minimum required ECCS equipment.

The CS System (Ref. 1) is composed of two independent subsystems. Each subsystem consists of two motor driven pumps, a spray sparger above the core, and piping and valves to transfer water from the suppression pool to the sparger. The CS System is designed to provide cooling to the reactor core when reactor pressure is low. Upon receipt of an initiation signal, the CS pumps in both subsystems are automatically started when AC power is available. When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow testing of the CS System without spraying water in the RPV.

LPCI is an independent operating mode of the RHR System. There are two LPCI subsystems (Ref. 2), each consisting of two motor driven pumps and piping and valves to transfer water from the suppression pool to the RPV via the corresponding recirculation loop. The two LPCI subsystems can be interconnected via the RHR System cross tie valves; however, at least one of the two cross tie valves is maintained closed with its power removed to prevent loss of both LPCI subsystems during a LOCA. The LPCI subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal, all four LPCI pumps are automatically started. RHR System valves in the LPCI flow path are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the recirculation loops. When the RPV pressure drops sufficiently, the LPCI flow to the RPV, via the corresponding recirculation loop, begins. The water then enters the reactor through the jet pumps.

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BASES

BACKGROUND (continued)

Full flow test lines are provided for each LPCI subsystem to route water from the suppression pool, to allow testing of the LPCI pumps without injecting water into the RPV. These test lines also provide suppression pool cooling capability, as described in LCO 3.6.2.3, "RHR Suppression Pool Cooling."

The HPCI System (Ref. 3) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping for the system is provided from the CST and the suppression pool. Pump suction for HPCI is normally aligned to the CST source to minimize injection of suppression pool water into the RPV. Whenever the CST water supply is low, an automatic transfer to the suppression pool water source ensures an adequate suction head for the pump and an uninterrupted water supply for continuous operation of the HPCI System. The steam supply to the HPCI turbine is piped from a main steam line upstream of the associated inboard main steam isolation valve.

The HPCI System is designed to provide core cooling for a wide range of reactor pressures (165 psia to 1225 psia). Upon receipt of an initiation signal, the HPCI turbine stop valve and turbine control valve open and the turbine accelerates to a specified speed. As the HPCI flow increases, the turbine control valve is automatically adjusted to maintain design flow. Exhaust steam from the HPCI turbine is discharged to the suppression pool. A full flow test line is provided to route water to the CST to allow testing of the HPCI System during normal operation without injecting water into the RPV.

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valves in these lines automatically open to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, all ECCS pump discharge lines are filled with water. The HPCI, LPCI and CS System discharge lines are kept full of water using a "keep fill" system that is supplied using the condensate transfer system.

(continued)

BASES

BACKGROUND (continued)

The ADS (Ref. 4) consists of 6 of the 16 S/RVs. It is designed to provide depressurization of the RCS during a small break LOCA if HPCI fails or is unable to maintain required water level in the RPV. ADS operation reduces the RPV pressure to within the operating pressure range of the low pressure ECCS subsystems (CS and LPCI), so that these subsystems can provide coolant inventory makeup. Each of the S/RVs used for automatic depressurization is equipped with two gas accumulators and associated inlet check valves. The accumulators provide the pneumatic power to actuate the valves.

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated LOCA. The accidents for which ECCS operation is required are presented in References 5, 6, and 7. The required analyses and assumptions are defined in Reference 8. The results of these analyses are also described in Reference 9.

This LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 10), will be met following a LOCA, assuming the worst case single active component failure in the ECCS:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. The core is maintained in a coolable geometry; and

e. Adequate long term cooling capability is maintained.

SPC performed LOCA calculations for the SPC ATRIUM™-10 fuel design. The limiting single failures for the SPC analyses are discussed in Reference 11. For a large break LOCA, the SPC analyses identify the recirculation loop suction piping as the limiting break location. The SPC analysis identifies the failure of the LPCI injection valve into the intact recirculation loop as the most limiting single failure.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

For a small break LOCA, the SPC analyses identify the recirculation loop discharge piping as the limiting break location, and a battery failure as the most severe single failure. One ADS valve failure is analyzed as a limiting single failure for events requiring ADS operation. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of the NRC Policy Statement (Ref. 15).

LCO

Each ECCS injection/spray subsystem and six ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the two CS subsystems, the two LPCI subsystems, and one HPCI System. The low pressure ECCS injection/spray subsystems are defined as the two CS subsystems and the two LPCI subsystems.

With less than the required number of ECCS subsystems OPERABLE, the potential exists that during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in Reference 10 could be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by Reference 10.

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3, when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, when reactor steam dome

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BASES

APPLICABILITY (continued)

pressure is ≤ 150 psig, ADS and HPCI are not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, ECCS—Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

If any one low pressure ECCS injection/spray subsystem is inoperable for reasons other than Condition B, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is based on a reliability study (Ref. 12) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

B.1

If one LPCI pump in one or both LPCI subsystems is inoperable, the inoperable LPCI pumps must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE LPCI pumps and at least one CS subsystem provide adequate core cooling during a LOCA.

However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. A 7 day Completion Time is based on a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

(continued)

BASES

ACTIONS

C.1 and C.2

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

D.1 and D:2

If the HPCI System is inoperable and the RCIC System is verified to be OPERABLE, the HPCI System must be restored to OPERABLE status within 14 days. In this Condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Verification of RCIC OPERABILITY is therefore required when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be verified, however, Condition H must be immediately entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is based on a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

E.1 and E.2

If Condition A or Condition B exists in addition to an inoperable HPCI System, the inoperable low pressure ECCS injection/spray subsystem or the LPCI pump(s) or the HPCI System must be restored to OPERABLE status within 72 hours. In this Condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is significantly reduced because a single failure in one of the remaining OPERABLE subsystems

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since both a high pressure system (HPCI) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the HPCI System or the low pressure ECCS injection/spray subsystem to OPERABLE status. This Completion Time is based on a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

F.1

The LCO requires six ADS valves to be OPERABLE in order to provide the ADS function. Reference 11 contains the results of an analysis that evaluated the effect of one ADS valve being out of service. Per this analysis, operation of only five ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced, because a single failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. The 14 day Completion Time is based on a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

G.1 and G.2

If Condition A or Condition B exists in addition to one inoperable ADS valve, adequate core cooling is ensured by the OPERABILITY of HPCI and the remaining low pressure ECCS injection/spray subsystem. However, overall ECCS reliability is reduced because a single active component failure concurrent with a design basis LOCA could result in the minimum required ECCS equipment not being available. Since both a high pressure system (ADS) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

(continued)

BASES

H.1 and H.2

If any Required Action and associated Completion Time of Condition D, E, F, or G is not met, or if two or more ADS valves are inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

I.1

When multiple ECCS subsystems are inoperable, as stated in Condition I, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the HPCI System, CS System, and LPCI subsystems full of water ensures that the ECCS will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring that the lines are full is to vent at the high points. The 31 day Frequency is based on the gradual nature of void buildup in the ECCS piping, the procedural controls governing system operation, and operating experience.

SR 3.5.1.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.2 (continued)

the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the HPCI System, this SR also includes the steam flow path for the turbine and the flow controller position.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve position would only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.

This SR is modified by a Note that allows LPCI subsystems to be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than the RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. This allows operation in the RHR shutdown cooling mode during MODE 3, if necessary.

SR 3.5.1.3

Verification every 31 days that ADS gas supply header pressure is $\geq$ 135 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 one 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 $\geq$ 135 psig is provided by the containment instrument gas system. The 31 day Frequency takes into consideration administrative controls over operation of the gas system and alarms associated with the containment instrument gas system.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.4

Verification every 31 days that at least one RHR System cross tie valve is closed and power to its operator is disconnected ensures that each LPCI subsystem remains independent and a failure of the flow path in one subsystem will not affect the flow path of the other LPCI subsystem. Acceptable methods of removing power to the operator include opening the breaker, or racking out the breaker, or removing the breaker. If both RHR System cross tie valves are open or power has not been removed from at least one closed valve operator, both LPCI subsystems must be considered inoperable. The 31 day Frequency has been found acceptable, considering that these valves are under strict administrative controls that will ensure the valves continue to remain closed with motive power removed.

SR 3.5.1.5

Verification every 31 days that each 480 volt AC swing bus transfers automatically from the normal source to the alternate source on loss of power while supplying its respective bus demonstrates that electrical power is available to ensure proper operation of the associated LPCI inboard injection and minimum flow valves and the recirculation pump discharge and bypass valves. Therefore, each 480 volt AC swing bus must be OPERABLE for the associated LPCI subsystem to be OPERABLE. The test is performed by actuating the load test switch or by disconnecting the preferred power source to the transfer switch and verifying that swing bus automatic transfer is accomplished. The 31 day Frequency has been found to be acceptable through operating experience.

SR 3.5.1.6

Cycling the recirculation pump discharge and bypass valves through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and provides assurance that the valves will close when required to ensure the proper LPCI flow path is established. Upon initiation of an automatic LPCI subsystem injection signal, these valves are required to be closed to ensure full LPCI subsystem flow injection in the reactor via the recirculation jet pumps. De-energizing the valve in the closed position will also ensure the proper flow path for the LPCI subsystem. Acceptable methods of de-energizing the valve include opening the breaker, or racking out the breaker, or removing the breaker.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.6 (continued)

The specified Frequency is once during reactor startup before THERMAL POWER is > 25% RTP. However, this SR is modified by a Note that states the Surveillance is only required to be performed if the last performance was more than 31 days ago. Therefore, implementation of this Note requires this test to be performed during reactor startup before exceeding 25% RTP. Verification during reactor startup prior to reaching > 25% RTP is an exception to the normal Inservice Testing Program generic valve cycling Frequency of 92 days, but is considered acceptable due to the demonstrated reliability of these valves. If the valve is inoperable and in the open position, the associated LPCI subsystem must be declared inoperable.

SR 3.5.1.7, SR 3.5.1.8, and SR 3.5.1.9

The performance requirements of the low pressure ECCS pumps are determined through application of the 10 CFR 50, Appendix K criteria (Ref. 8). This periodic Surveillance is performed (in accordance with the ASME Code, Section XI, requirements for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The low pressure ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of Reference 10. The pump flow rates are verified against a system head equivalent to the RPV pressure expected during a LOCA. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during a LOCA. These values may be established during preoperational testing.

The flow tests for the HPCI System are performed at two different pressure ranges such that system capability to provide rated flow is tested at both the higher and lower operating ranges of the system. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the HPCI System diverts steam flow. Reactor steam pressure is considered adequate when ≥ 920 psig to perform SR 3.5.1.8 and ≥ 150 psig to perform SR 3.5.1.9. However, the requirements of SR 3.5.1.9 are met by a successful performance at any pressure ≤ 165 psig. Adequate steam flow is represented by at least 1.25 turbine bypass valves open. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these tests. Reactor startup is allowed prior to performing the low pressure Surveillance test because the reactor pressure is low and the time allowed to satisfactorily

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7, SR 3.5.1.8, and SR 3.5.1.9 (continued)

perform the Surveillance test is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that HPCI is inoperable.

Therefore, SR 3.5.1.8 and SR 3.5.1.9 are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test.

The Frequency for SR 3.5.1.7 and SR 3.5.1.8 is in accordance with the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.1.9 is based on the need to perform the Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.1.10

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCI, CS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup and actuation of all automatic valves to their required positions. This functional test includes the LPCI and CS interlocks between Unit 1 and Unit 2 and specifically requires the following:

A functional test of the interlocks associated with the LPCI and CS pump starts in response to an automatic initiation signal in Unit 1 followed by a false automatic initiation signal in Unit 2;

A functional test of the interlocks associated with the LPCI and CS pump starts in response to an automatic initiation signal in Unit 2 followed by a false automatic initiation signal in Unit 1; and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.10 (continued)

A functional test of the interlocks associated with the LPCI and CS pump starts in response to simultaneous occurrences of an automatic initiation signal in both Unit 1 and Unit 2 and a loss of Offsite power condition affecting both Unit 1 and Unit 2.

The purpose of this functional test (preferred pump logic) is to assure that if a false LOCA signal were to be received on one Unit simultaneously with an actual LOCA signal on the second Unit, the preferred LPCI and CS pumps are started and the non-preferred LPCI and CS pumps are tripped for each Unit. This functional test is performed by verifying that the non-preferred LPCI and CS pumps are tripped. The verification that preferred LPCI and CS pumps start is performed under a separate surveillance test. Only one division of LPCI preferred pump logic is required to be OPERABLE for each Unit, because no additional failures needs to be postulated with a false LOCA signal. If the preferred or non-preferred pump logic for CS is inoperable, the associated CS pumps shall be declared inoperable and the pumps should not be operated to ensure that the opposite Unit's CS pumps or 4.16 kV ESS Buses are protected.

This SR also ensures that the HPCI System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlaps this Surveillance. This SR can be accomplished by any series of sequential overlapping or total steps such that the entire channel is tested.

The 24 month Frequency is acceptable because operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.11

The ADS designated S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to demonstrate that the mechanical portions of the ADS function (i.e., solenoids) operate as designed when initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components. SR 3.5.1.12 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform portions of the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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

SR 3.5.1.12

A manual actuation of each ADS valve is performed to verify that the valve and solenoid are functioning properly. This is demonstrated by one of the two methods described below. Proper operation of the valve tailpipes is ensured through the use of foreign material exclusion during maintenance.

One method is by manual actuation of ADS valve under hot conditions. Proper functioning of the valve and solenoid is demonstrated by the response of turbine control or bypass valve or by a change in the measured flow or by any other method suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve due to seat impact during closure. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the ADS valves divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this SR. Adequate pressure at which this SR is to be performed is 150 psig. However, the requirements of SR 3.5.1.12 are met by a successful performance at any pressure. Adequate steam flow is represented by at least 1.25 turbine bypass valves open. Reactor startup is allowed prior to performing this SR by this method because valve OPERABILITY and the setpoints for

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.12 (continued)

overpressure protection are verified, per ASME requirements, prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions and provides adequate time to complete the Surveillance.

Another method is by manual actuation of the ADS valve at atmospheric temperature and pressure during cold shutdown. When using this method, proper functioning of the valve and solenoid is demonstrated by visual observation of actuator movement. Actual disc travel is measured during valve refurbishment and testing per ASME requirements. Lifting the valve at atmospheric pressure requires controlling the actuator to set the valve disc softly on its seat to prevent valve damage. Lifting of the valves at atmospheric pressure is the preferred method because lifting the valves with steam flow increases the likelihood that the valve will leak. The Note that modified this SR is not needed when this method is used because the SR is performed during cold shutdown.

SR 3.5.1.11 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function. The Frequency of 24 months on a STAGGERED TEST BASIS ensures that both solenoids for each ADS valve are alternately tested. The Frequency is based on the need to perform the Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.1.13

This SR ensures that the ECCS RESPONSE TIME for each ECCS injection/spray subsystem is less than or equal to the maximum value assumed in the accident analysis. Response Time testing acceptance criteria are included in Reference 13. This SR is modified by a Note that allows the instrumentation portion of the response time to be assumed to be based on historical response time data and therefore, is excluded from the ECCS RESPONSE TIME testing. This is allowed since the instrumentation response time is a small part of the ECCS RESPONSE TIME (e.g., sufficient margin exists in the diesel generator start time when compared to the instrumentation response time) (Ref. 14).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.13 (continued)

The 24 month Frequency is consistent with the typical industry refueling cycle and is acceptable based upon plant operating experience.

REFERENCES

1. FSAR, Section 6.3.2.2.3.
2. FSAR, Section 6.3.2.2.4.
3. FSAR, Section 6.3.2.2.1.
4. FSAR, Section 6.3.2.2.2.
5. FSAR, Section 15.2.4.
6. FSAR, Section 15.2.5.
7. FSAR, Section 15.2.6.
8. 10 CFR 50, Appendix K.
9. FSAR, Section 6.3.3.
10. 10 CFR 50.46.
11. FSAR, Section 6.3.3.
12. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
13. FSAR, Section 6.3.3.3.
14. NEDO 32291-A, "System Analysis for the Elimination of Selected Response Time Testing Requirements, October 1995.
15. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.3 RCIC System

BASES

BACKGROUND

The RCIC System is not part of the ECCS; however, the RCIC System is included with the ECCS section because of their similar functions.

The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of the RPV water level. Under these conditions, the High Pressure Coolant Injection (HPCI) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

The RCIC System (Ref. 2) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping is provided from the condensate storage tank (CST) and the suppression pool. Pump suction is normally aligned to the CST to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, an automatic transfer to the suppression pool water source ensures an adequate suction head for the pump and an uninterrupted water supply for continuous operation of the RCIC System. The steam to the turbine is piped from a main steam line upstream of the associated inboard main steam line isolation valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures (165 psia to 1225 psia). Upon receipt of an initiation signal, the RCIC turbine accelerates to a specified speed. As the RCIC flow increases, the turbine control valve is automatically adjusted to maintain design flow. Exhaust steam from the RCIC turbine is discharged to the suppression pool. A full flow test line is provided to route water to the CST to allow testing of the RCIC System during normal operation without injecting water into the RPV.

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BASES

BACKGROUND (continued)	The RCIC pump is provided with a minimum flow bypass line, which discharges to the suppression pool. The valve in this line automatically opens to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the RCIC System discharge piping is kept full of water. The RCIC System is normally aligned to the CST. The RCIC discharge line is kept full of water using a "keep fill" system supplied by the condensate transfer system.
APPLICABLE SAFETY ANALYSES	The function of the RCIC System is to respond to transient events by providing makeup coolant to the reactor. The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analyses for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the system is included in the Technical Specifications, as required by the NRC Policy Statement (Ref. 4).
LCO	The OPERABILITY of the RCIC System provides adequate core cooling such that actuation of any of the low pressure ECCS subsystems is not required in the event of RPV isolation accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity for maintaining RPV inventory during an isolation event.
APPLICABILITY	The RCIC System is required to be OPERABLE during MODE 1, and MODES 2 and 3 with reactor steam dome pressure >150 psig, since RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure ≤ 150 psig, and in MODES 4 and 5, RCIC is not required to be OPERABLE since the low pressure ECCS injection/spray subsystems can provide sufficient flow to the RPV.
ACTIONS	A Note prohibits the application of LCO 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable RCIC system and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

If the RCIC System is inoperable during MODE 1, or MODE 2 or 3 with reactor steam dome pressure >150 psig, and the HPCI System is verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days. In this Condition, loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high reactor pressure since the HPCI System is the only high pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of HPCI is therefore verified immediately when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine if HPCI is out of service for maintenance or other reasons. It does not mean it is necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the HPCI System. If the OPERABILITY of the HPCI System cannot be verified, however, Condition B must be immediately entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCI) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of the RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC to OPERABLE status.

The 14 day Completion Time is based on a reliability study (Ref. 3) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (AOTs). Because of similar functions of HPCI and RCIC, the AOYs (i.e., Completion Times) determined for HPCI are also applied to RCIC.

B.1 and B.2

If the RCIC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCI System is simultaneously inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. The allowed Completion Times

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge line of the RCIC System full of water ensures that the system will perform properly, injecting its full capacity into the Reactor Coolant System upon demand. This will also prevent a water hammer following an initiation signal. One acceptable method of ensuring the line is full is to vent at the high points. The 31 day Frequency is based on the gradual nature of void buildup in the RCIC piping, the procedural controls governing system operation, and operating experience.

SR 3.5.3.2

Verifying the correct alignment for manual, power operated, and automatic valves in the RCIC flow path provides assurance that the proper flow path will exist for RCIC operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a non-accident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the RCIC System, this SR also includes the steam flow path for the turbine and the flow controller position.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.2 (continued)

31 days is further justified because the valves are operated under procedural control and because improper valve position would affect only the RCIC System. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.3.3 and SR 3.5.3.4

The RCIC pump flow rtes ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. The flow tests for the RCIC System are performed at two different pressure ranges such that system capability to provide rated flow is tested both at the higher and lower operating ranges of the system. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the RCIC System diverts steam flow. Reactor steam pressure is considered adequate when ≥ 920 psig to perform SR 3.5.3.3 and ≥ 150 psig to perform SR 3:5.3.4. However, the requirements of SR 3.5.3.4 are met by a successful performance at any pressure ≤ 165 psig. Adequate steam flow is represented by at least 1.25 turbine bypass valves open. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform those SRs. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure Surveillance has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Therefore, these SRs are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test.

The Frequency for SR 3.5.3.3 is determined by the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.3.4 is based on the need to perform the Surveillance under conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is base on the refueling

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.3, and SR 3.5.3.4 (continued)

cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.3.5

The RCIC System is required to actuate automatically in order to verify its design function satisfactorily. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of the RCIC System will cause the system to operate as designed, including actuation of the system throughout its emergency operating sequence; that is, automatic pump startup and actuation of all automatic valves to their required positions. This test also ensures the RCIC System will automatically restart on a n RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2 overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform portions of the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes vessel injection 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.

REFERENCES

1. 10 CFE 50, Appendix A, GDC 33.

2. FSAR, Section 5.4.6.

(continued)

BASES

REFERENCES (continued)

3. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components", December 1, 1975.

4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Primary Containment Hydrogen Recombiners

BASES

BACKGROUND

The primary containment hydrogen recombiner eliminates the potential breach of primary containment due to a hydrogen oxygen reaction and is part of combustible gas control required by 10 CFR 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Reactors" (Ref. 1), and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2). The primary containment hydrogen recombiner is required to reduce the hydrogen concentration in the primary containment following a loss of coolant accident (LOCA). The primary containment hydrogen recombiner accomplishes this by recombining hydrogen and oxygen to form water vapor. The vapor remains in the primary containment, thus eliminating any discharge to the environment. The primary containment hydrogen recombiner is manually initiated since flammability limits would not be reached until several days after a Design Basis Accident (DBA).

The primary containment hydrogen recombiner functions to maintain the hydrogen gas concentration within the containment at or below the flammability limit of 4.0 volume percent (v/o) following a postulated LOCA. Two 100 percent capacity hydrogen recombiner systems are located in the drywell and suppression chamber to meet the single failure criterion. Each hydrogen recombiner system has two hydrogen recombiner units, one located in the drywell and one located in the suppression chamber, for a total of four hydrogen recombiners per unit.

The hydrogen recombiner is a natural convection, flameless, thermal reactor-type hydrogen/oxygen recombiner. The recombiner heats a continuous stream of containment atmosphere to a temperature sufficient for recombination of the hydrogen and oxygen to form water.

The recombination unit consists of an inlet preheater section, a heater-recombination section, and a mixing chamber. The air is drawn into the unit by natural convection via the inlet louvers and passes through the preheater section, which consists of a shroud placed around the central heaters to take advantage of heat conduction

(continued)

BASES

BACKGROUND (continued)

through the walls. In this area, the temperature of the inlet air is raised. This accomplishes the dual function of increasing the system efficiency and of evaporating any moisture droplets which may be entrained in the air. The warmed air then passes through the flow orifice which has been specifically sized to regulate the airflow through the unit. After passing through the orifice plate, the air flows vertically upward through the heater section, where its temperature is raised to the range of 1150-1400°F, causing recombination of hydrogen and oxygen to occur. The recombination temperature is approximately 1135°F. The heater section consists of five banks of electric heaters stacked vertically. Each bank contains 60 individual U-type heating elements.

APPLICABLE SAFETY ANALYSES

The primary containment hydrogen recombiner provides the capability of controlling the bulk hydrogen concentration in primary containment to less than the lower flammable concentration of 4.0 v/o following a DBA. This control would prevent a primary containment wide hydrogen burn, thus ensuring that pressure and temperature conditions assumed in the analysis are not exceeded. The limiting DBA relative to hydrogen generation is a LOCA.

Hydrogen may accumulate in primary containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant; or

b. Radiolytic decomposition of water in the Reactor Coolant System.

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation is calculated as a function of time following the initiation of the accident. Assumptions recommended by Reference 3 are used to maximize the amount of hydrogen calculated.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)	The calculation confirms that when the mitigating systems are actuated in accordance with emergency procedures, the peak hydrogen concentration in the primary containment is < 4.0 v/o (Ref. 4). The primary containment hydrogen recombiners satisfy Criterion 3 of the NRC Policy Statement. (Ref. 5)
LCO	Two drywell and two suppression chamber hydrogen recombiners must be OPERABLE. This ensures operation of at least one drywell and one suppression chamber hydrogen recombiner subsystem in the event of a worst case single active failure. Operation with at least one drywell and one suppression chamber hydrogen recombiner subsystem ensures that the post-LOCA hydrogen concentration can be prevented from exceeding the flammability limit.
APPLICABILITY	In MODES 1 and 2, the two drywell and two suppression chamber hydrogen recombiners are required to control the hydrogen concentration within primary containment below its flammability limit of 4.0 v/o following a LOCA, assuming a worst case single failure. In MODE 3, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the primary containment hydrogen recombiner is low. Therefore, the primary containment hydrogen recombiner is not required in MODE 3. In MODES 4 and 5, the probability and consequences of a LOCA are low due to the pressure and temperature limitations in these MODES. Therefore, the primary containment hydrogen recombiners are not required in these MODES.

(continued)

BASES (continued)

ACTIONS

A.1

With one drywell and/or one suppression chamber hydrogen recombiner inoperable, the inoperable recombiners must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE recombiners are adequate to perform the hydrogen control function. However, the overall reliability is reduced because a single failure in the OPERABLE recombiner could result in reduced hydrogen control capability. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the amount of time available after the event for operator action to prevent exceeding this limit, and the low probability of failure of the OPERABLE primary containment hydrogen recombiner.

B.1 and B.2

With two drywell, or two suppression chamber, or 3 or more hydrogen recombiners inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by the containment nitrogen purge system. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure its continued availability. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two drywell and/or two suppression chamber hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two drywell and/or two suppression chamber hydrogen recombiners to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit.

C.1

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

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1.1

Performance of a system functional test for each primary containment hydrogen recombiner ensures that the recombiners are OPERABLE and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR verifies that the minimum heater sheath temperature is maintained > 1150°F and < 1400°F for ≥ 4 hours thereafter to check the ability of the recombiner to function properly (and to make sure that significant heater elements are not burned out). Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.1.2

This SR ensures there are no physical problems that could affect recombiner operation. Since the recombiners are mechanically passive they are subject to only minimal mechanical failure. The only credible failures involve loss of power or blockage of the internal flow path, missile impact, etc.

A visual inspection is sufficient to determine abnormal conditions that could cause such failures. The visual inspection will include looking for loose wiring or structural connections, deposits of foreign materials, etc. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.1.3

This SR requires performance of a resistance to ground test of each heater phase following energization to make sure that there are no detectable grounds in any heater phase. This is accomplished by verifying that the resistance to ground for any heater phase is $\geq$ 10,000 ohms.

Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50.44.
2. 10 CFR 50, Appendix A, GDC 41.
3. Regulatory Guide 1.7, Revision 1.
4. FSAR, Section 6.2.5.
5. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Drywell Air Flow System

BASES

BACKGROUND

The Drywell Cooling fans in low speed ensure a uniformly mixed post accident primary containment atmosphere (Ref. 1), thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

The Drywell Cooling fans are an Engineered Safety Feature and are designed to withstand a loss of coolant accident (LOCA) in post accident environments without loss of function. The system consists of three required pairs of fans with each pair consisting of two independent fans. The three required Drywell Cooling fan pairs are as follows:

a. Drywell Unit Cooler fans 2V414A/2V414B;

b. Drywell Unit Cooler fans 2V416A/21V416B;

c. Recirculation fan 2V418A/2V418B.

The fans are initiated manually since flammability limits would not be reached until several days after a LOCA. Each fan in a pair is powered from a separate emergency power supply. Since one fan in each pair can provide 100% of the mixing requirements, the system will provide its design function with a worst case single active failure.

APPLICABLE SAFETY ANALYSES

The Drywell Cooling fans provide the capability for reducing the local hydrogen concentration to approximately the bulk average concentration following a Design Basis Accident (DBA). The limiting DBA relative to hydrogen generation is a LOCA.

Hydrogen may accumulate in primary containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant; or

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

b. Radiolytic decomposition of water in the Reactor Coolant System.

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 2 are used to maximize the amount of hydrogen calculated.

The Reference 3 calculations show that hydrogen assumed to be released to the drywell following a DBA LOCA raises drywell hydrogen concentration to over 2.5 volume percent (v/o) within 1.2 days. Although natural circulation phenomena reduces the gradient concentration differences in containment, a containment mixing system provides further means of preventing local hydrogen gas buildups in containment post-accident.

The Drywell Cooling fans satisfy Criterion 3 of the NRC Policy Statement. (Ref. 4)

LCO

Three required Drywell Cooling fan pairs must be OPERABLE in low speed to ensure operation of at least one fan in each of the required pairs in the event of a worst case single active failure. The three required Drywell Cooling fan pairs are as follows:

a. Drywell Unit Cooler fans 2V414A/2V414B;

b. Drywell Unit Cooler fans 2V416A/2V416B;

c. Recirculation fan 2V418A/2V418B.

Operation with at least one fan in each required pair provides the capability of controlling the bulk hydrogen concentration in primary containment without exceeding the flammability limit.

APPLICABILITY

In MODES 1 and 2, the three Drywell Cooling fan pairs ensure the capability to prevent localized hydrogen concentrations

(continued)

BASES

APPLICABILITY (continued)

above the flammability limit of 4.0 v/o in drywell, assuming a worst case single active failure.

In MODE 3, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the Drywell Cooling fans is low. Therefore, the Drywell Cooling fans are not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, the Drywell Cooling fans are not required in these MODES.

ACTIONS

A.1

With one required Drywell Cooling fan in one or more pairs inoperable, the inoperable fan must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE fan is adequate to perform the hydrogen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE fan could result in reduced hydrogen mixing capability. The 30 day Completion Time is based on the availability of the second fan, the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the amount of time available after the event for operator action to prevent exceeding this limit, and the availability of the Primary Containment Hydrogen Recombiner System.

(continued)

BASES

ACTIONS (continued)

B.1 and B. 2

With two required Drywell Cooling fans in one or more pairs inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by the containment nitrogen purge system. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure its continued availability. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two Drywell Cooling fans in one or more pairs inoperable for up to 7 days. Seven days is a reasonable time to allow two Drywell Cooling fans in one or more pairs to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit.

C.1

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

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1

Operating each required Drywell Cooling fan in low speed from the control room for ≥ 15 minutes ensures that each

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1 (continued)

subsystem is OPERABLE and that all associated controls are functioning properly. Since required fans are operated at high speed during normal operations this SR ensures the low speed motor circuits operate. The 92 day Frequency is consistent with the Inservice Testing Program Frequencies, operating experience, the known reliability of the fan motors and controls, and the two redundant fans available.

REFERENCES

1. FSAR 9.4.5
2. Regulatory Guide 1.7, Revision 1.
3. FSAR, Section 6.2.5.
4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of two offsite power sources (preferred power sources, normal and alternate), and the onsite standby power sources (diesel generators (DGs) A, B, C and D). A fifth diesel generator, DG E, can be used as a substitute for any one of the four DGs A, B, C or D. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system is divided into redundant load groups, so loss of any one group does not prevent the minimum safety functions from being performed. Each load group has connections to two preferred offsite power supplies and a single DG.

The two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System are supported by two independent offsite power sources. A 230 kV line from the Susquehanna T10 230 kV switching station feeds start-up transformer No. 10; and, a 230 kV tap from the 500-230 kV tie line feeds the startup transformer No. 20.

The two independent offsite power sources are supplied to and are shared by both units. These two electrically and physically separated circuits provide AC power, through startup transformers (ST) No. 10 and ST No. 20, to the four 4.16 kV Engineered Safeguards System (ESS) buses (A, B, C and D) for both Unit 1 and Unit 2. A detailed description of the offsite power network and circuits to the onsite Class 1E ESS buses is found in the FSAR, Section 8.2 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, automatic tap changers, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESS bus or buses.

(continued)

BASES

BACKGROUND (continued)

ST No. 10 and ST No. 20 each provide the normal source of power to two of the four 4.16 kV ESS buses in each Unit and the alternate source of power to the remaining two 4.16 kV ESS buses in each Unit. If any 4.16 kV ESS bus loses power, an automatic transfer from the normal to the alternate occurs after the normal supply breaker trips.

When off-site power is available to the 4.16 kV ESS Buses following a LOCA signal, the required ESS loads will be sequenced onto the 4.16 kV ESS Buses in order to compensate for voltage drops in the onsite power system when starting large ESS motors.

The onsite standby power source for 4.16 kV ESS buses A, B, C and D consists of five DGs. DGs A, B, C and D are dedicated to ESS buses A, B, C and D, respectively. DG E can be used as a substitute for any one of the four DGs (A, B, C or D) to supply the associated ESS bus. Each DG provides standby power to two 4.16 kV ESS buses—one associated with Unit 1 and one associated with Unit 2. The four "required" DGs are those aligned to a 4.16 kV ESS bus to provide onsite standby power for both Unit 1 and Unit 2.

A DG, when aligned to an ESS bus, starts automatically on a loss of coolant accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or on an ESS bus degraded voltage or undervoltage signal. After the DG has started, it automatically ties to its respective bus after offsite power is tripped as a consequence of ESS bus undervoltage or degraded voltage, independent of or coincident with a LOCA signal. The DGs also start and operate in the standby mode without tying to the ESS bus on a LOCA signal alone. Following the trip of offsite power, non-permanent loads are stripped from the 4.16 kV ESS Buses. When a DG is tied to the ESS Bus, loads are then sequentially connected to their respective ESS Bus by individual load timers. The individual load timers control the starting permissive signal to motor breakers to prevent overloading the associated DG.

In the event of loss of normal and alternate offsite power supplies, the 4.16 kV ESS buses will shed all loads except the 480 V load centers and the standby diesel generators will connect to the ESS busses. When a DG is tied to its respective ESS bus, loads are then sequentially connected to

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BASES

BACKGROUND (continued)

the ESS bus by individual load timers which control the permissive and starting signals to motor breakers to prevent overloading the DG.

In the event of a loss of normal and alternate offsite power supplies, the ESS electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a LOCA.

Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading of the DGs in the process. Within 286 seconds after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service. Ratings for the DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3).

DGs A, B, C and D have the following ratings:

a. 4000 kW—continuous,
b. 4700 kW—2000 hours,

DG E has the following ratings:

a. 5000 kW—continuous,
b. 5500 kW—2000 hours.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit and supporting safe shutdown of the other unit. This includes maintaining the onsite or offsite AC sources

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

OPERABLE during accident conditions in the event of an assumed loss of all offsite power or all onsite AC power; and a worst case single failure.

AC sources satisfy Criterion 3 of the NRC Policy Statement (Ref. 6).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System and four separate and independent DGs (A, B, C and D) ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA. DG E can be used as a substitute for any one of the four DGs A, B, C or D.

Qualified offsite circuits are those that are described in the FSAR, and are part of the licensing basis for the unit. In addition, the required automatic load timers for each ESF bus shall be OPERABLE.

The Safety Analysis for Unit 2 assumes the OPERABILITY of some equipment that receives power from Unit 1 AC Sources. Therefore, Unit 2 Technical Specifications establish requirements for the OPERABILITY of the DG(s) and qualified offsite circuits needed to support the Unit 1 onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.7, Distribution Systems—Operating.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESS buses. One OPERABLE offsite circuit consists of an energized ST. No. 10 transformer and the respective circuit path including energized ESS transformers 101 and 111 and feeder breakers capable of supplying three of the four 4.16 kV ESS Buses. The other OPERABLE offsite circuit consists of an energized ST. No. 20 transformer, and the respective circuit path including energized ESS transformers 201 and 211 and feeder breakers capable of supplying three of the four 4.16 kV ESS Buses. Both offsite circuits are OPERABLE provided each meets the criteria described above and provided that no 4.16 kV ESS Bus has less than one OPERABLE offsite circuit

(continued)

BASES

LCO (continued)

capable of supplying the required loads. If no OPERABLE offsite circuit is capable of supplying any of the 4.16 kV ESS Buses, provided that the offsite circuits otherwise meet the above requirements, one offsite source shall be declared inoperable. Unit 2 also requires Unit 1 offsite circuits to be OPERABLE.

Four of the five DGs are required to be Operable to satisfy the initial assumptions of the accident analyses. Each required DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESS bus on detection of bus undervoltage after the normal and alternate supply breakers open. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESS buses. These capabilities are required to be met from a variety of initial conditions, such as DG in standby with the engine hot and DG in normal standby conditions. Normal standby conditions for a DG mean that the diesel engine oil is being continuously circulated and engine coolant is circulated as necessary to maintain temperature consistent with manufacturer recommendations. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

Although not normally aligned as a required DG, DG E is normally maintained OPERABLE (i.e., Surveillance Testing completed) so that it can be used as a substitute for any one of the four DGs A, B, C or D.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources must be separate and independent (to the extent possible) of other AC sources. For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical. A circuit may be connected to more than one ESS bus, with automatic transfer capability to the other circuit OPERABLE, and not violate separation criteria. A circuit that is not connected to an ESS bus is required to

(continued)

BASES

LCO (continued)	have OPERABLE automatic transfer interlock mechanisms to each ESS bus to support OPERABILITY of that offsite circuit.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 4 and 5 are covered in LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The ACTIONS are modified by a Note which allows entry into associated Conditions and Required Actions to be delayed for up to 8 hours when an OPERABLE diesel generator is placed in an inoperable status for the alignment of diesel generator E to or from the Class 1E distribution system. Use of this allowance requires both offsite circuits to be OPERABLE. Entry into the appropriate Conditions and Required Actions shall be made immediately upon the determination that substitution of a required diesel generator will not or can not be completed.

A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the availability of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

(continued)

BASES

ACTIONS (continued)

A.2

Required Action A.2, which only applies if one 4.16 kV ESS bus cannot be powered from any offsite source, is intended to provide assurance that an event with a coincident single failure of the associated DG does not result in a complete loss of safety function of critical systems. These features (e.g., system, subsystem, division, component, or device) are designed to be powered from redundant safety related 4.16 kV ESS buses. Redundant required features failures consist of inoperable features associated with an emergency bus redundant to the emergency bus that has no offsite power. The Completion Time for Required Action A.2 is intended to allow time for the operator to evaluate and repair any discovered inoperabilities. This Completion Time also allows an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. A 4.16 kV ESS bus has no offsite power supplying its loads; and

b. A redundant required feature on another 4.16 kV ESS bus is inoperable.

If, at any time during the existence of this Condition (one offsite circuit inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering no offsite power to one 4.16 kV ESS bus on the onsite Class 1E Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with any other emergency bus that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before the unit is subjected to transients associated with shutdown.

The remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24

(continued)

BASES

ACTIONS

A.2 (continued)

hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A

(continued)

BASES

ACTIONS

A.3 (continued)

and B are entered concurrently. The "AND" connector between the 72 hours and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

A temporary Completion Time is connected to the Completion Time requirements above (72 hours and six days from discovery of failure to meet LCO) with an "OR" connector. The temporary Completion Time is 10 days and applies to the replacement of the Startup Transformer Number 10. The temporary Completion Time of 10 days expires on December 31, 2003. If during the conduct of the prescribed Startup Transformer Number 10 Replacement, should any combination of the remaining operable AC sources be determined inoperable (on an individual unit basis), current TS requirements would apply.

B.1

To ensure a highly reliable power source remains with one required DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

(continued)

BASES

ACTIONS

B.2 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature powered from another diesel generator (Division 1 or 2) is inoperable.

If, at any time during the existence of this Condition (one required DG inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DGs results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.7 does not have to be performed. If the cause of inoperability exists on other DG(s), they are declared inoperable upon discovery, and Condition E of

(continued)

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be determined not to exist on the remaining DG(s), performance of SR 3.8.1.7 suffices to provide assurance of continued OPERABILITY of those DGs. However, the second Completion Time for Required Action B.3.2 allows a performance of SR 3.8.1.7 completed up to 24 hours prior to entering Condition B to be accepted as demonstration that a DG is not inoperable due to a common cause failure.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 8), 24 hours is a reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

B.4

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition B for a period that should not exceed 72 hours. In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure of the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to

(continued)

BASES

ACTIONS

B.4 (continued)

complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met, instead of the time that Condition B was entered.

C.1

Required Action C.1 addresses actions to be taken in the event of concurrent inoperability of two offsite circuits. The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities.

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this degradation level:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

(continued)

BASES

ACTIONS

C.1 (continued)

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria. According to Regulatory Guide 1.93 (Ref. 7), with the available offsite AC sources two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System Actions would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any ESS bus, Actions for LCO 3.8.7, "Distribution Systems-Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of the offsite circuit and one DG without regard to whether a division is de-energized. LCO 3.8.7 provides the appropriate restrictions for a de-energized bus.

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition D for a period that should not exceed 12 hours. In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

E.1

With two or more DGs inoperable and an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for the majority of ESF equipment at this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown. (The immediate shutdown could cause grid instability, which could result in a total loss of AC power.) Since any inadvertent unit generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Regulatory Guide 1.93 (Ref. 7), with two or more DGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 and F.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

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

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 11), as addressed in the FSAR.

The Safety Analysis for Unit 2 assumes the OPERABILITY of some equipment that receives power from Unit 1 AC Sources. Therefore, Surveillance requirements are established for the Unit 1 onsite Class 1E AC electrical power distribution subsystem(s) required to support Unit 2 by LCO 3.8.7, Distribution Systems—Operating. As Noted at the beginning of the SRs, SR 3.8.1.1 through SR 3.8.1.20 are applicable to the Unit 2 AC sources and SR 3.8.1.21 is applicable to the Unit 1 AC sources.

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 3793 V is the value assumed in the degraded voltage analysis and is approximately 90% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of

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BASES

SURVEILLANCE REQUIREMENTS (continued)

4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4400 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations found in Regulatory Guide 1.9 (Ref. 3). The lower Frequency Limit is necessary to support the LOCA analysis assumptions for low pressure ECCS pump flow rates. (Reference 12)

The Surveillance Table has been modified by a Note, to clarify the testing requirements associated with DG E. The Note is necessary to define the intent of the Surveillance Requirements associated with the integration of DG E. Specifically, the Note defines that a DG is only considered OPERABLE and required when it is aligned to the Class 1E distribution system.. For example, if DG A does not meet the requirements of a specific SR, but DG E is substituted for DG A and aligned to the Class 1E distribution system, DG E is required to be OPERABLE to satisfy the LCO requirement of 4 DGs and DG A is not required to be OPERABLE because it is not aligned to the Class 1E distribution system. This is acceptable because only 4 DGs are assumed in the event analysis. Furthermore, the Note identifies when the Surveillance Requirements, as modified by SR Notes, have been met and performed, DG E can be substituted for any other DG and declared OPERABLE after performance of two SRs which verify switch alignment. This is acceptable because the testing regimen defined in the Surveillance Requirement Table ensures DG E is fully capable of performing all DG requirements.

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 (continued)

correct position to ensure that distribution buses and loads are connected to an Operable offsite power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2

Not Used.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing and accepting greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the Cooper Bessemer Service Bulletin 728, so that mechanical stress and wear on the diesel engine are minimized.

Note 2 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test. Similarly, momentary power factor transients do not invalidate the test.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

Note 5 provides the allowance that DG E, when not aligned as substitute for DG A, B, C and D but being maintained available, may use the test facility to satisfy loading requirements in lieu of synchronization with an ESS bus.

Note 6 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units, with the DG synchronized to the 4.16 kV ESS bus of Unit 1 for one periodic test and synchronized to the 4.16 kV ESS bus of Unit 2 during the next periodic test. This is acceptable because the purpose of the test is to demonstrate the ability of the DG to operate at its continuous rating (with the exception of DG E which is only required to be tested at the continuous rating of DGs A thru D) and this attribute is tested at the required Frequency. Each unit's circuit breakers and breaker control circuitry, which are only being tested every second test (due to the staggering of the tests), historically have a very low failure rate. If a DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit. In addition, if the test is scheduled to be performed on the other Unit, and the other Unit's TS allowance that provides an exception to performing the test is used (i.e., the Note to SR 3.8.2.1 for the other Unit provides an exception to performing this test when the other Unit is in MODE 4 or 5, or moving irradiated fuel assemblies in the secondary containment), or it is not possible to perform the test due to equipment availability, then the test shall be performed synchronized to this Unit's 4.16 kV ESS bus. The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR verifies the level of fuel oil in the engine mounted day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 55 minutes of DG A-D and 62 minutes of DG E operation at DG continuous rated load conditions.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

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 water from the engine mounted day 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 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 (Ref. 11). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. It is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The Frequency for this SR is 31 days because the design of the fuel transfer system requires that the transfer pumps operate automatically. Administrative controls ensure an adequate volume of fuel oil in the day tanks. This Frequency allows this aspect of DG Operability to be demonstrated during or following routine DG operation.

SR 3.8.1.7

This SR helps to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, this SR has been modified by Note 1 to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period (which for DGs A through D includes operation of the lube oil system to ensure the DG's turbo charger is sufficiently prelubicated to prevent undo wear and tear).

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (continued)

The DG starts from standby conditions and achieves the minimum required voltage and frequency within 10 seconds and maintains the required voltage and frequency when steady state conditions are reached. The ten second start requirement support the assumptions in the design bases LOCA analysis of FSAR Section 6.3 (Ref. 12)

To minimize testing of the DGs, Note 2 allows a single test to satisfy the requirements for both units (instead of two tests, one for each unit). This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to one unit.

The time for the DG to reach steady state operation is periodically monitored and the trend evaluated to identify degradation.

The 31 day Frequency is consistent with Regulatory Guide 1.9 (Ref. 3). This Frequency provides adequate assurance of DG OPERABILITY.

SR 3.8.1.8

Transfer of each 4.16 kV ESS bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 24 month Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed on the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of the automatic transfer of unit power supply could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

result, plant safety systems. The manual transfer of unit power supply should not result in any perturbation to the electrical distribution system, therefore, no mode restriction is specified. This Surveillance tests the applicable logic associated with Unit 2. The comparable test specified in Unit 1 Technical Specifications tests the applicable logic associated with Unit 1. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1 or 2 does not have applicability to Unit 1. The NOTE only applies to Unit 2, thus the Unit 2 Surveillance shall not be performed with Unit 2 in MODE 1 or 2.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The largest single load for each a DG is a residual heat removal (RHR) pump (1425 kW). This Surveillance may be accomplished by:

a. Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus; or

b. Tripping its associated single largest post-accident load with the DG solely supplying the bus.

As recommended by Regulatory Guide 1.9 (Ref. 3), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower. For DGs A, B, C, D and E, this represents 64.5 Hz, equivalent to 75% of the

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

difference between nominal speed and the overspeed trip setpoint.

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 4.5 seconds specified is equal to 60% of the 7.5 second load sequence interval between loading of the RHR and core spray pumps during an undervoltage on the bus concurrent with a LOCA. The 6 seconds specified is equal to 80% of that load sequence interval. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c specify the steady state voltage and frequency values to which the system must recover following load rejection.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

To minimize testing of the DGs, a Note allows a single test to satisfy the requirements for both units (instead of two tests, one for each unit). This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event, and continues to be available, this response ensures that the DG

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

To minimize testing of the DGs, a Note allows a single test to satisfy the requirements for both units (instead of two tests, one for each unit). This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

SR 3.8.1.11

As required by Regulatory Guide 1.9 (Ref. 3), this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the ESS buses and respective 4.16 kV loads from the DG. It further demonstrates the capability of the DG to automatically achieve and maintain the required voltage and frequency within the specified time.

The DG auto-start time of 10 seconds is derived from requirements of the licensed accident analysis for responding to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. Note 1

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

allows all DG starts to be preceded by an engine prelube period (which for DG's A through D includes operation of he lube oil system to ensure the DGs turbo charger is sufficiently prelubricated). For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine oil being continuously circulated and engine coolant being circulated as necessary to maintain temperature consistent with manufacturer recommendations.

The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 2. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with Unit 1. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 1. The Note only applies to Unit 2, thus the Unit 2 Surveillances shall not be performed with Unit 2 in MODES 1, 2 or 3.

This SR is also modified by Note 3. The Note specifies when this SR is required to be performed for the DGs and the 4.16 kV ESS Buses. The Note is necessary because this SR involves an integrated test between the DGs and the 4.16 kV ESS Buses and the need for the testing regimen to include DG E being tested (substituted for all DGs for both units) with all 4.16 kV ESS Buses. To ensure the necessary testing is performed, the following rotational testing regimen has been established:

UNIT IN OUTAGE	DIESEL E SUBSTITUTED FOR
2	DG E not tested
1	Diesel Generator D
2	Diesel Generator A
1	DG E not tested
2	Diesel Generator B
1	Diesel Generator A
2	Diesel Generator C
1	Diesel Generator B
2	Diesel Generator D
1	Diesel Generator C

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The specified rotational testing regimen can be altered to facilitate unanticipated events which render the testing regimen impractical to implement, but any alternative testing regimen must provide an equivalent level of testing.

This SR does not have to be performed with the normally aligned DG when the associated 4.16 kV ESS bus is tested using DG E and DG E does not need to be tested when not substituted or aligned to the Class 1E distribution system. The allowances specified in the Note are acceptable because the tested attributes of each of the five DGs and each unit's four 4.16 kV ESS buses are verified at the specified Frequency (i.e., each DG and each 4.16 kV ESS bus is tested every 24 months). Specifically, when DG E is tested with a Unit 1 4.16 kV ESS bus, the attributes of the normally aligned DG, although not tested with the Unit 1 4.16 kV ESS bus, are tested with the Unit 2 4.16 kV ESS bus within the 24 month Frequency. The testing allowances do result in some circuit pathways which do not need to change state (i.e., cabling) not being tested on a 24 month Frequency. This is acceptable because these components are not required to change state to perform their safety function and when substituted–normal operation of DG E will ensure continuity of most of the cabling not tested.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on a LOCA signal without loss of offsite power.

The requirement to verify the connection and power supply of permanent and auto connected loads is intended to satisfactorily show the relationship of these loads to the loading logic for loading onto offsite power. In certain circumstances, many of these loads cannot actually be

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified. SR 3.8.1.12.a through SR 3.8.1.12.d are performed with the DG running. SR 3.8.1.12.e can be performed when the DG is not running.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. Note 1 allows all DG starts to be preceded by an engine prelube period (which for DGs A through D includes operation of the lube oil system to ensure the DG's turbo charger is sufficiently prelubricated). For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine oil being continuously circulated and engine coolant being circulated as necessary to maintain temperature consistent with manufacturer recommendations.

The reason for Note 2 is to allow DG E, when not aligned as substitute for DG A, B, C or D, to use the test facility to satisfy loading requirements in lieu of aligning with the Class 1E distribution system. When tested in this configuration, DG E satisfies the requirements of this test by completion of SR 3.8.1.12.a, b and c only. SR 3.8.1.12.d and 3.8.1.12.e may be performed by any DG aligned with the Class 1E distribution system or by any series of sequential,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

overlapping, or total steps so that the entire connection and loading sequence is verified.

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on an ECCS initiation test signal. The non-critical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 24 month Frequency is based on engineering judgment, takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The SR is modified by two Notes. To minimize testing of the DGs, Note 1 to SR 3.8.1.13 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit.

Note 2 provides the allowance that DG E, when not aligned as a substitute for DG A, B, C, and D but being maintained available, may use a simulated ECCS initiation signal.

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), requires demonstration once per 24 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours—22 hours of which is at a load equivalent to 90% to 100% of the continuous rating of the DG, and 2 hours of which is at a load equivalent to 105% to 110% of the continuous duty rating of the DG. SSES has taken exception to this

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

requirement and performs the two hour run at the 2000 hour rating for each DG. The requirement to perform the two hour overload test can be performed in any order provided it is performed during a single continuous time period.

The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube discussed in SR 3.8.1.7, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

A load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance has been modified by four Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test.

To minimize testing of the DGs, Note 2 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit.

Note 3 stipulates that DG E, when not aligned as substitute for DG A, B, C or D but being maintained available may use the test facility to satisfy the specified loading requirements in lieu of synchronization with an ESS bus.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from full load temperatures and achieve the required voltage

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by three Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Momentary transients due to changing bus loads do not invalidate this test.

Note 2 allows all DG starts to be preceded by an engine prelube period (which for DGs A through D includes operation of the lube oil system to ensure the DG's turbocharger is sufficiently prelubricated) to minimize wear and tear on the diesel during testing.

To minimize testing of the DGs, Note 3 allows a single test to satisfy the requirements for both units (instead of two tests, one for each unit). This is acceptable because this test is intended to demonstrate attributes of the DG that are not associated with either Unit. If the DG fails this Surveillance, the DG should be considered inoperable for both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3), this Surveillance ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the DG controls are in isochronous and the output breaker is open.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a note to accommodate the testing regimen necessary for DG E. See SR 3.8.1.11 for the Bases of the Note.

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage, the DG controls in isochronous, and the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 10), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirements associated with SR 3.8.1.17.b is to show that the emergency loading is not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This test is performed by verifying that after the DG is tripped, the offsite source originally in parallel with the DG, remains connected to the affected 4.16 kV ESS Bus. SR 3.8.1.12 is performed separately to verify the proper offsite loading sequence.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a note to accommodate the testing regimen necessary for DG E. See SR 3.8.1.11 for the Bases of the Note.

Under accident conditions, loads are sequentially connected to the bus by individual load timers which control the permissive and starting signals to motor breakers to prevent overloading of the AC Sources due to high motor starting currents. The load sequence time interval tolerance ensures that sufficient time exists for the AC Source to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESS buses. A list of the required timers and the associated setpoints are included in the Bases as Table B 3.8.1-1, Unit 1 and Unit 2 Load Timers. Failure of a timer identified as an offsite power timer may result in both offsite sources inoperable. Failure of any other timer may result in the associated DG being inoperable. A timer is considered failed for this SR if it will not ensure that the associated load will energize within the Allowable Value specified in Table B 3.8.1-1. These conditions will require entry into applicable Condition of this specification. With a load timer inoperable, the load can be rendered inoperable to restore OPERABILITY to the associated AC sources. In this condition, the Conditions and Required Actions of the associated specification shall be entered for the equipment rendered inoperable.

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

SR 3.8.1.18

This SR is modified by a Note that specifies that load timers associated with equipment that has automatic initiation

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

capability disabled are not required to be Operable. This is acceptable because if the load does not start automatically, the adverse effects of an improper loading sequence are eliminated. Furthermore, load timers are associated with individual timers such that a single timer only affects a single load.

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified. To simulate the non-LOCA unit 4.16 kV ESS Bus loads on the DG, bounding loads are energized on the tested 4.16 kV ESS Bus after all auto connected emergency loads are energized.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. Note 1 allows all DG starts to be preceded by an engine prelube period (which for DGs A through D includes operation of the lube oil system to ensure the DG's turbo charger is sufficiently prelubricated). For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine oil being continuously circulated and

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

engine coolant being circulated as necessary to maintain temperature consistent with manufacturer recommendations.

Note 2 is necessary to accommodate the testing regimen associated with DG E. See SR 3.8.1.11 for the Bases of the Note.

The reason for Note 3 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This Surveillance tests the applicable logic associated with Unit 2. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with Unit 1. Consequently, a test must be performed within the specified Frequency for each unit. As the Surveillance represents separate tests, the Note specifying the restriction for not performing the test while the unit is in MODE 1, 2 or 3 does not have applicability to Unit 1. The Note only applies to Unit 2, thus the Unit 2 Surveillances shall not be performed with Unit 2 in MODE 1, 2 or 3.

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously. The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. The Note allows all DG starts to be preceded by an engine prelube period (which for DGs A through D includes operation of the lube oil system to ensure the DG's turbo charger is sufficiently prelubricated.) For the purpose of this testing, the DG's must be started from standby conditions, that is, with the engine oil continuously circulated and engine coolant being circulated as necessary to maintain temperature consistent with manufacturer recommendations.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

Note 2 is necessary to identify that this test does not have to be performed with DG E substituted for any DG. The allowance is acceptable based on the design of the DG E transfer switches. The transfer of control, protection, indication, and alarms is by switches at two separate locations. These switches provide a double break between DG E and the redundant system within the transfer switch panel. The transfer of power is through circuit breakers at two separate locations for each redundant system. There are four normally empty switchgear positions at DG E facility, associated with each of the four existing DGs. Only one circuit breaker is available at this location to be inserted into one of the four positions. At each of the existing DGs, there are two switchgear positions with only one circuit breaker available. This design provides two open circuits between redundant power sources. Therefore, based on the described design, it can be concluded that DG redundancy and independence is maintained regardless of whether DG E is substituted for any other DG.

SR 3.8.1.21

This Surveillance is provided to direct that the appropriate Surveillances for Unit 1 AC sources required to support Unit 2 are governed by the Unit 2 Technical Specifications. With the exception of this Surveillance, all other Surveillances of this Specification (SR 3.8.1.1 through SR 3.8.1.20) are applicable to the Unit 2 AC sources only. Meeting the SR requirements of Unit 1 LCO 3.8.1 will satisfy all Unit 2 requirements for Unit 1 AC sources. However, six Unit 1 LCO 3.8.1 SRs, if not required to support Unit 1 OPERABILITY requirements, are not required when demonstrating Unit 1 sources are capable of supporting Unit 2. SR 3.8.1.8 is not required if only one Unit 1 offsite circuit is required by the Unit 2 Specification. SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.17, and SR 3.8.1.19 are not required since these SRs test the Unit 2 ECCS initiation signal, which is not needed for the AC sources to be OPERABLE on Unit 2. SR 3.8.1.20 is not required since starting independence is not required with the DG(s) not required to be OPERABLE.

The Frequency required by the applicable Unit 1 SR also governs performance of that SR for Unit 2.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

As Noted, if Unit 1 is in MODE 4 or 5, the Note to Unit 1 SR 3.8.2.1 is applicable. This ensures that a Unit 2 SR will not require a Unit 1 SR to be performed, when the Unit 1 Technical Specifications do not require performance of a Unit 1 SR. (However, as stated in the Unit 2 SR 3.8.2.1 Note, while performance of an SR is not required, the SR still must be met).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Section 8.2.
3. Regulatory Guide 1.9.
4. FSAR, Chapter 6.
5. FSAR, Chapter 15.
6. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
7. Regulatory Guide 1.93.
8. Generic Letter 84-15.
9. 10 CFR 50, Appendix A, GDC 18.
10. IEEE Standard 308.
11. Regulatory Guide 1.137.
12. FSAR, Section 6.3.
13. ASME Boiler and Pressure Vessel Code, Section XI.

TABLE B 3.8.1-1 (page 1 of 2)
UNIT 1 AND UNIT 2 LOAD TIMERS

DEVICE TAG NO.	SYSTEM LOADING TIMER	LOCATION	NOMINAL SETTING (seconds)	ALLOWABLE VALUE (seconds)
62A-20102	RHR Pump 1A	1A201	3	≥ 2.7 and ≤ 3.6
62A-20202	RHR Pump 1B	1A202	3	≥ 2.7 and ≤ 3.6
62A-20302	RHR Pump 1C	1A203	3	≥ 2.7 and ≤ 3.6
62A-20402	RHR Pump 1D	1A204	3	≥ 2.7 and ≤ 3.6
62A-20102	RHR Pump 2A	2A201	3	≥ 2.7 and ≤ 3.6
62A-20202	RHR Pump 2B	2A202	3	≥ 2.7 and ≤ 3.6
62A-20302	RHR Pump 2C	2A203	3	≥ 2.7 and ≤ 3.6
62A-20402	RHR Pump 2D	2A204	3	≥ 2.7 and ≤ 3.6
E11A-K202B	RHR Pump 1C (Offsite Power Timer)	1C618	7.0	≥ 6.5 and ≤ 7.5
E11A-K120A	RHR Pump 1C (Offsite Power Timer)	1C617	7.0	≥ 6.5 and ≤ 7.5
E11A-K120B	RHR Pump 1D (Offsite Power Timer)	1C618	7.0	≥ 6.5 and ≤ 7.5
E11A-K202A	RHR Pump 1D (Offsite Power Timer)	1C617	7.0	≥ 6.5 and ≤ 7.5
E11A-K120A	RHR Pump 2C (Offsite Power Timer)	2C617	7.0	≥ 6.5 and ≤ 7.5
E11A-K202B	RHR Pump 2C (Offsite Power Timer)	2C618	7.0	≥ 6.5 and ≤ 7.5
E11A-K120B	RHR Pump 2D (Offsite Power Timer)	2C618	7.0	≥ 6.5 and ≤ 7.5
E11A-K202A	RHR Pump 2D (Offsite Power Timer)	2C617	7.0	≥ 6.5 and ≤ 7.5
E21A-K116A	CS Pump 1A	1C626	10.5	≥ 9.4 and ≤ 11.6
E21A-K116B	CS Pump 1B	1C627	10.5	≥ 9.4 and ≤ 11.6
E21A-K125A	CS Pump 1C	1C626	10.5	≥ 9.4 and ≤ 11.6
E21A-K125B	CS Pump 1D	1C627	10.5	≥ 9.4 and ≤ 11.6
E21A-K116A	CS Pump 2A	2C626	10.5	≥ 9.4 and ≤ 11.6
E21A-K116B	CS Pump 2B	2C627	10.5	≥ 9.4 and ≤ 11.6
E21A-K125A	CS Pump 2C	2C626	10.5	≥ 9.4 and ≤ 11.6
E21A-K125B	CS Pump 2D	2C627	10.5	≥ 9.4 and ≤ 11.6
E21A-K16A	CS Pump 1A (Offsite Power Timer)	1C626	15	≥ 14.0 and ≤ 16.0
E21A-K16B	CS Pump 1B (Offsite Power Timer)	1C627	15	≥ 14.0 and ≤ 16.0
E21A-K25A	CS Pump 1C (Offsite Power Timer)	1C626	15	≥ 14.0 and ≤ 16.0
E21A-K25B	CS Pump 1D (Offsite Power Timer)	1C627	15	≥ 14.0 and ≤ 16.0
E21A-K16A	CS Pump 2A (Offsite Power Timer)	2C626	15	≥ 14.0 and ≤ 16.0
E21A-K16B	CS Pump 2B (Offsite Power Timer)	2C627	15	≥ 14.0 and ≤ 16.0
E21A-K25A	CS Pump 2C (Offsite Power Timer)	2C626	15	≥ 14.0 and ≤ 16.0
E21A-K25B	CS Pump 2D (Offsite Power Timer)	2C627	15	≥ 14.0 and ≤ 16.0
62AX2-20108	Emergency Service Water	1A201	40	≥ 36 and ≤ 44
62AX2-20208	Emergency Service Water	1A202	40	≥ 36 and ≤ 44
62AX2-20303	Emergency Service Water	1A203	44	≥ 39.6 and ≤ 48.4
62AX2-20403	Emergency Service Water	1A204	48	≥ 43.2 and ≤ 52.8
62X3-20404	Control Structure Chilled Water System	OC877B	60	≥ 54
62X3-20304	Control Structure Chilled Water System	OC877A	60	≥ 54
62X-20104	Emergency Switchgear Rm Cooler A & RHR SW Pump H&V Fan A	OC877A	60	≥ 54
62X-20204	Emergency Switchgear Rm Cooler B & RHR SW Pump H&V Fan B	OC877B	60	≥ 54
62X-5653A	DG Room Exhaust Fan E3	OB565	60	≥ 54
62X-5652A	DG Room Exhausts Fan E4	OB565	60	≥ 54
262X-20204	Emergency Switchgear Rm Cooler B	OC877B	120	≥ 54
262X-20104	Emergency Switchgear Rm Cooler A	OC877A	120	≥ 54
62X-546	DG Rm Exh Fan D	OB546	120	≥ 54

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TABLE B 3.8.1-1 (page 2 of 2)
UNIT 1 AND UNIT 2 LOAD TIMERS

DEVICE TAG NO.	SYSTEM LOADING TIMER	LOCATION	NOMINAL SETTING (seconds)	ALLOWABLE VALUE (seconds)
62X-536	DG Rm Exh Fan C	OB536	120	≥ 54
62X-526	DG Rm Exh Fan B	OB526	120	≥ 54
62X-516	DG Rm Exh Fan A	OB516	120	≥ 54
CRX-5652A	DG Room Supply Fans E1 and E2	OB565	120	≥ 54
62X2-20410	Control Structure Chilled Water System	OC876B	180	≥ 54
62X1-20304	Control Structure Chilled Water System	OC877A	180	≥ 54
62X2-20310	Control Structure Chilled Water System	OC876A	180	≥ 54
62X1-20404	Control Structure Chilled Water System	OC877B	180	≥ 54
62X2-20304	Control Structure Chilled Water System	OC877A	210	≥ 54
62X2-20404	Control Structure Chilled Water System	OC877B	210	≥ 54
62X-K11BB	Emergency Switchgear Rm Cooling Compressor B	2CB250B	260	≥ 54
62X-K11AB	Emergency Switchgear Rm Cooling Compressor A	2CB250A	260	≥ 54