AmerGen

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An Exelon Company

10 CFR 50.90

RS-07-074
June 21, 2007

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

Clinton Power Station, Unit 1
Facility Operating License No. NPF-62
NRC Docket No. 50-461

Subject: Application for Technical Specification Change TSTF-423, Risk Informed Modification to Selected Required Action End States for BWR Plants, Using the Consolidated Line Item Improvement Process

Reference: TSTF-423, Revision 0, "Technical Specifications End States, NEDC-32988-A"

In accordance with 10 CFR 50.90, "Application for amendment of license or construction permit," AmerGen Energy Company, LLC (AmerGen) is requesting a change to the Technical Specifications (TS) of Facility Operating License No. NPF-62 for Clinton Power Station (CPS), Unit 1. The proposed amendment would modify TS to risk-informed requirements regarding selected Required Action End States as provided in the referenced document.

Attachment 1 provides a description of the proposed changes, the requested confirmation of applicability, and plant-specific verifications. Attachment 2 provides the existing TS pages marked up to show the proposed changes. Attachment 3 provides the existing TS Bases pages marked up to show the proposed changes. The TS Bases pages are provided for information only and do not require NRC approval. Attachment 4 provides a summary of the regulatory commitments made in this submittal.

Changes to TS are consistent with the changes outlined in the referenced document; minor deviations are discussed in Attachment 1. CPS, Unit 1 TS are based on NUREG-1434, "Standard Technical Specifications General Electric Plants, BWR/6," though it is not identical to this guidance. Therefore, an adaptation of the referenced document was required.

AmerGen requests approval of the proposed license amendment by June 21, 2008, with implementation within 120 days of issuance.

This amendment request has been reviewed and approved by the CPS Plant Operations Review Committee and the Nuclear Safety Review Board in accordance with the requirements of the Quality Assurance Program and procedures.

In accordance with 10 CFR 50.91, "Notice for public comment," AmerGen is notifying the State of Illinois of this application for amendment by transmitting a copy of this letter and its attachments to the designated State Official.

If you have any questions concerning this letter, please contact Ms. Michelle Yun at (630) 657-2818.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 21 day of June 2007.

Respectfully,

Darin M. Benyak
Director – Licensing and Regulatory Affairs
AmerGen Energy Company, LLC

Attachment 1: Description and Assessment
Attachment 2: Mark-up of Proposed Technical Specification Changes
Attachment 3: Mark-up of Technical Specification Bases Changes
Attachment 4: List of Regulatory Commitments

ATTACHMENT 1
Description and Assessment

Subject: Application for Technical Specification Change TSTF-423, Risk Informed Modification to Selected Required Action End States for BWR Plants, Using the Consolidated Line Item Improvement Process

ATTACHMENT 1
Description and Assessment

1.0 DESCRIPTION

The proposed amendment would modify Technical Specifications (TS) to risk-informed requirements regarding selected Required Action End States.

The changes are consistent with the Nuclear Regulatory Commission (NRC) approved Industry/Technical Specification Task Force (TSTF) TSTF-423, Revision 0, "Technical Specifications End States, NEDC-32988-A," except as described in Section 2.2 below. The availability of this TS improvement was published in the *Federal Register* on March 23, 2006 as part of the Consolidated Line Item Improvement Process (CLIIP).

2.0 ASSESSMENT

2.1 Applicability of Topical Report, TSTF-423, and Published Safety Evaluation

AmerGen Energy Company, LLC (AmerGen) has reviewed the General Electric (GE) topical report (i.e., Reference 1), TSTF-423 (i.e., Reference 2), and the NRC model safety evaluation (i.e., Reference 3) as part of the CLIIP. AmerGen has concluded that the information in the GE topical report and TSTF-423, as well as the safety evaluation prepared by the NRC, are applicable to Clinton Power Station (CPS), Unit 1 and provide justification for the incorporation of the proposed changes into the CPS, Unit 1 TS.

2.2 Optional Changes and Variations

AmerGen is proposing the following variations or deviations from the GE topical report, TS changes described in the TSTF-423, Revision 0, or the NRC's model safety evaluation, dated March 23, 2006.

TSTF-423 is based on NUREG-1434, "Standard Technical Specifications General Electric Plants, BWR/6." CPS, Unit 1 TS are based on NUREG-1434, but are not identical to this guidance. As a result, an adaptation of TSTF-423 was required, in some cases, for incorporation into the CPS, Unit 1 TS due to minor administrative differences in format (e.g., condition letter designation, etc).

Changes made to CPS TS 3.6.1.9, "Feedwater Leakage Control System (FWLCS)," are identical to those made in TSTF-423 for STS 3.6.1.8, "Penetration Valve Leakage Control System (PVLCS)." The FWLCS at CPS serves a similar design purpose as the PVLCS described in STS 3.6.1.8 and CPS, Unit 1 TS 3.6.1.9 was modeled after the STS for the PVLCS.

Changes made to CPS TS 3.6.2.3, "Residual Heat Removal (RHR) Suppression Pool Cooling," are in accordance with the changes made in TSTF-423 for STS 3.6.2.3, "Residual Heat Removal (RHR) Suppression Pool Cooling," with the exception of the action associated with two inoperable RHR Suppression Pool Cooling subsystems. Condition B of STS 3.6.2.3 allows a completion time of 8 hours to return one RHR Suppression Pool Cooling subsystem to operable status in the event two RHR Suppression Pool Cooling subsystems are inoperable. Since CPS TS 3.6.2.3 currently requires entry into Mode 3 and Mode 4 in the event that two RHR Suppression Pool

Cooling subsystems are inoperable, this required action is maintained in the proposed CPS TS 3.6.2.3 markup.

The TS changes in TSTF-423, Revision 0 included changes to STS sections 3.4.4, "Safety/Relief valves (S/RVs)," and 3.6.1.9, "Main Steam Isolation Valve (MSIV) Leakage Control System (LCS)," which are not applicable to the CPS, Unit 1 TS. The CPS, Unit 1 TS 3.4.4 Conditions differ from those in STS 3.4.4 such that the technical justification provided in Reference 1 is not directly applicable. Specifically, CPS, Unit 1 TS 3.4.4 Condition A addresses one or more S/RVs inoperable; whereas, STS 3.4.4 Condition A is limited to a single inoperable S/RV. The CPS, Unit 1 TS do not contain the equivalent of STS 3.6.1.9. Therefore, the aforementioned TSTF changes are not part of this submittal.

3.0 REGULATORY ANALYSIS

3.1 No Significant Hazards Consideration Determination

AmerGen Energy Company, LLC (AmerGen) has reviewed the proposed No Significant Hazards Consideration Determination (NSHCD) published in the *Federal Register* as part of the Consolidated Line Item Improvement Process (CLIIP), (i.e., Reference 3). AmerGen has concluded that the proposed NSHCD presented in the *Federal Register* notice is applicable to Clinton Power Station (CPS), Unit 1 and is hereby incorporated by reference to satisfy the requirements of 10 CFR 50.91(a), "Notice for public comment."

3.2 Verification and Commitments

As discussed in the notice of availability published in Reference 3 for this TS improvement, plant-specific verifications were performed as follows.

AmerGen commits to the regulatory commitments in Attachment 4. In addition, AmerGen has proposed TS Bases consistent with the GE topical report and TSTF-423, which provide guidance and details on how to implement the new requirements. Implementation of TSTF-423 requires that risk be managed and assessed. AmerGen's configuration risk management program is adequate to satisfy this requirement. The risk assessment need not be quantified, but may be a qualitative assessment of the vulnerability of systems and components when one or more systems are not able to perform their associated function. Furthermore, AmerGen has a Bases Control Program consistent with Section 5.5 of the STS.

4.0 ENVIRONMENTAL EVALUATION

The proposed amendment affects requirements with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR 20, "Standards for Protection Against Radiation." The NRC has determined that the amendment adopting TSTF-423, Revision 0, involves no significant increases in amounts of effluents that may be released offsite, no significant changes in the types of effluents that may be released offsite, and no significant increases in the individual or cumulative occupational radiation exposure. The NRC has previously issued a

proposed finding that TSTF-423, Revision 0, involves no significant hazards considerations and there has been no public comment on said finding in the *Federal Register,* Notice 70 FR 74037, December 14, 2005. The amendment request meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9), "Criterion for categorical exclusion." In accordance with 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of this amendment.

5.0 IMPACT ON PREVIOUS SUBMITTALS

The amendment seeks to execute changes on TS that currently have pending amendments. The following TS have an associated amendment pending:

TSTF-448, Control Room Habitability	3.7.3	Submitted 4/12/07

6.0 REFERENCES

1. NEDC-32988-A, Revision 2, "Technical Justification to Support Risk-Informed Modification to Selected Required Action End States for BWR Plants," December 2002
2. TSTF-423, Revision 0, "Technical Specifications End States, NEDC-32988-A"
3. Volume 71, Federal Register, Page 14726 (71FRN14726), "Notice of Availability of Model Application Concerning Technical Specifications for Boiling Water Reactor Plants to Risk-Inform Requirements Regarding Selected Required Action End States Using the Consolidated Line Item Improvement Process," dated March 23, 2006

ATTACHMENT 2

Mark-up of Proposed Technical Specification Changes

3.3 -81
3.5 -2
3.5 -3
3.6 -1
3.6 -22
3.6 -24
3.6 -27a
3.6 -32
3.6 -43
3.6 -51
3.6 -52
3.6 -69
3.7 -1
3.7 -2
3.7 -4
3.7 -5
3.7 -8
3.7 -11
3.8 -3
3.8 -24
3.8 -34
3.8 -35
3.8 -40

3.3 INSTRUMENTATION

3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

LCO 3.3.8.2 One RPS electric power monitoring assembly shall be OPERABLE for each inservice RPS special solenoid power supply or alternate power supply.

APPLICABILITY: MODES 1, 2, and 3,
MODES 4 and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or both inservice power supplies with the electric power monitoring assembly inoperable.	A.1 Remove associated inservice power supply(s) from service.	1 hour
B. Required Action and associated Completion Time of Condition A not met in MODE 1, 2, or 3.	B.1 Be in MODE 3. ~~AND~~ ~~B.2 Be in MODE 4.~~	12 hours ~~36 hours~~
C. Required Action and associated Completion Time of Condition A not met in MODE 4 or 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	C.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two ECCS injection subsystems inoperable. OR One ECCS injection and one ECCS spray subsystem inoperable.	C.1 Restore one ECCS injection/spray subsystem to OPERABLE status.	72 hours
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Be in MODE 3. ~~AND~~ ~~D.2 Be in MODE 4.~~	12 hours ~~36 hours~~
E. One ADS valve inoperable.	E.1 Restore ADS valve to OPERABLE status.	14 days
F. One ADS valve inoperable. AND One low pressure ECCS injection/spray subsystem inoperable.	F.1 Restore ADS valve to OPERABLE status. OR F.2 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours 72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Two or more ADS valves inoperable. OR Required Action and associated Completion Time of Condition E or F not met.	G.1 Be in MODE 3. ~~AND~~ ~~G.2 Reduce reactor steam dome pressure to ≤ 150 psig.~~	12 hours ~~36 hours~~
H. HPCS and Low Pressure Core Spray (LPCS) Systems inoperable. OR Three or more ECCS injection/spray subsystems inoperable. OR HPCS System and one or more ADS valves inoperable. OR Two or more ECCS injection/spray subsystems and one or more ADS valves inoperable.	H.1 Enter LCO 3.0.3.	Immediately

3.6 CONTAINMENT SYSTEMS

3.6.1.1 Primary Containment

LCO 3.6.1.1 Primary containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

----------NOTE----------
Applicable Conditions and Required Actions are not required to be entered for the Inclined Fuel Transfer System (IFTS) penetration for up to 12 hours per cycle when the IFTS blind flange is unbolted.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Primary containment inoperable.	A.1 Restore primary containment to OPERABLE status.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. ~~AND~~ ~~B.2 Be in MODE 4.~~	12 hours ~~36 hours~~

3.6 CONTAINMENT SYSTEMS

3.6.1.6 Low-Low Set (LLS) Valves

LCO 3.6.1.6 The LLS function of five safety/relief valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One LLS valve inoperable.	A.1 Restore LLS valve to OPERABLE status.	14 days
B. Required Action and associated Completion Time of Condition A not met. ~~OR~~	B.1 Be in MODE 3. ~~AND~~ ~~B.2 Be in MODE 4.~~	12 hours ~~36 hours~~
C. Two or more LLS valves inoperable.	C.1 Be in MODE 3. AND C.2 Be in MODE 4	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.1.7 Residual Heat Removal (RHR) Containment Spray System

LCO 3.6.1.7 Two RHR containment spray subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR containment spray subsystem inoperable.	A.1 Restore RHR containment spray subsystem to OPERABLE status.	7 days
B. Two RHR containment spray subsystems inoperable.	B.1 Restore one RHR containment spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. ~~AND~~ ~~C.2 Be in MODE 4.~~	12 hours ~~36 hours~~

3.6 CONTAINMENT SYSTEMS

3.6.1.9 Feedwater Leakage Control System (FWLCS)

LCO 3.6.1.9 Two FWLCS subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One FWLCS subsystem inoperable.	A.1 Restore FWLCS subsystem to OPERABLE status.	30 days
B. Two FWLCS subsystems inoperable.	B.1 Restore one FWLCS subsystem to OPERABLE status.	7 days
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. ~~AND~~ ~~C.2 Be in MODE 4.~~	12 hours ~~36 hours~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.9.1	Perform a system functional test of each FWLCS subsystem.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

LCO 3.6.2.3 Two RHR suppression pool cooling subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool cooling subsystem inoperable.	A.1 Restore RHR suppression pool cooling subsystem to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met. ~~OR~~	B.1 Be in MODE 3. ~~AND~~ ~~B.2 Be in MODE 4.~~	12 hours ~~36 hours~~
C. Two RHR suppression pool cooling subsystems inoperable.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.4.1 Secondary Containment

LCO 3.6.4.1 The secondary containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of recently irradiated fuel assemblies in the primary or secondary containment,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Secondary containment inoperable in MODE 1, 2, or 3.	A.1 Restore secondary containment to OPERABLE status.	4 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. ~~AND~~ ~~B.2 Be in MODE 4.~~	12 hours ~~36 hours~~

(continued)

3.6 CONTAINMENT SYSTEMS

3.6.4.3 Standby Gas Treatment (SGT) System

LCO 3.6.4.3 Two SGT subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of recently irradiated fuel assemblies in the primary or secondary containment,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One SGT subsystem inoperable.	A.1 Restore SGT subsystem to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met in MODE 1, 2, or 3.	B.1 Be in MODE 3. ~~AND~~ ~~B.2 Be in MODE 4.~~	12 hours ~~36 hours~~

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A not met during movement of recently irradiated fuel assemblies in the primary or secondary containment, or during OPDRVs.	----------NOTE---------- LCO 3.0.3 is not applicable. ----------	
	C.1 Place OPERABLE SGT subsystem in operation.	Immediately
	OR	
	C.2.1 Suspend movement of recently irradiated fuel assemblies in the primary and secondary containment.	Immediately
	AND	
	C.2.2 Initiate action to suspend OPDRVs.	Immediately
D. Two SGT subsystems inoperable in MODE 1, 2, or 3.	D.1 ~~Enter LCO 3.0.3.~~ Be in MODE 3.	~~Immediately~~ 12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two or more drywell post-LOCA vacuum relief subsystems inoperable for reasons other than Condition A.	C.1 Restore drywell post-LOCA vacuum relief subsystems to OPERABLE status.	72 hours
D. Required Action and associated Completion Time of Condition ~~A,~~ A. ~~B, or C not met.~~	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours
E. Required Action and associated Completion Time of Condition B or C not met.	E.1 Be in MODE 3.	12 hours

3.7 PLANT SYSTEMS

3.7.1 Division 1 and 2 Shutdown Service Water (SX) Subsystems and Ultimate Heat Sink (UHS)

LCO 3.7.1 Division 1 and 2 SX subsystems and the UHS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. UHS water volume not within limit.	A.1 Restore UHS water volume to within limit.	90 days
B. Division 1 or 2 SX subsystem inoperable.	----------NOTES---------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources—Operating," for diesel generator made inoperable by SX. 2. Enter applicable Conditions and Required Actions of LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," for RHR shutdown cooling subsystem made inoperable by SX. ---------- B.1 Restore SX subsystem to OPERABLE status.	72 hours

(continued)

C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3.	12 hours

Actions (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. ~~C.~~ Required Action and associated Completion Time of Condition A ~~or B~~ not met. OR Division 1 and 2 SX subsystems inoperable.	D ~~C~~.1 Be in MODE 3. AND D ~~C~~.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Verify UHS water volume is ≥ 593 acre-ft.	In accordance with UHS Erosion, Sediment Monitoring, and Dredging Program
SR 3.7.1.2	Verify each required SX subsystem manual, power operated, and automatic valve in the flow path servicing safety related systems or components, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.1.3	Verify each SX subsystem actuates on an actual or simulated initiation signal.	24 months

3.7 PLANT SYSTEM

3.7.3 Control Room Ventilation System

LCO 3.7.3 Two Control Room Ventilation subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the primary or secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One Control Room Ventilation subsystem inoperable.	A.1	Restore Control Room Ventilation subsystem to OPERABLE status.	7 days
B. Required Action and Associated Completion Time of Condition A not met in MODE 1, 2, or 3.	B.1	Be in MODE 3.	12 hours
	~~AND~~		
	~~B.2~~	~~Be in MODE 4.~~	~~36 hours~~

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A not met during movement of irradiated fuel assemblies in the primary or secondary containment, during CORE ALTERATIONS, or during OPDRVs.	----------NOTE---------- LCO 3.0.3 is not applicable. ----------	
	C.1 Place OPERABLE Control Room Ventilation subsystem in high radiation mode.	Immediately
	OR	
	C.2.1 Suspend movement of irradiated fuel assemblies in the primary and secondary containment.	Immediately
	AND	
	C.2.2 Suspend CORE ALTERATIONS.	Immediately
	AND	
	C.2.3 Initiate action to suspend OPDRVs.	Immediately
D. Two Control Room Ventilation subsystems inoperable in MODE 1, 2, or 3.	D.1 ~~Enter LCO 3.0.3~~. Be in MODE 3.	~~Immediately~~ 12 hours

(continued)

3.7 PLANT SYSTEMS

3.7.4 Control Room Air Conditioning (AC) System

LCO 3.7.4 Two control room AC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the primary or secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One control room AC subsystem inoperable.	A.1	Restore control room AC subsystem to OPERABLE status.	30 days
B. Two control room AC subsystems inoperable.	B.1	Verify control room area temperature ≤ 86 °F.	Once per 4 hours
	AND		
	B.2	Restore one control room AC subsystem to OPERABLE status.	7 days
C. Required Action and Associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1	Be in MODE 3.	12 hours
	~~AND~~		
	~~C.2~~	~~Be in MODE 4.~~	~~36 hours~~

(continued)

3.7 PLANT SYSTEMS

3.7.5 Main Condenser Offgas

LCO 3.7.5 The radioactivity rate of the noble gases measured at the offgas recombiner effluent shall be ≤ 289 mCi/second after decay of 30 minutes.

APPLICABILITY: MODE 1,
MODES 2 and 3 with any main steam line not isolated and steam jet air ejector (SJAE) in operation.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Radioactivity rate of the noble gases not within limit.	A.1	Restore radioactivity rate of the noble gases to within limit.	72 hours
B. Required Action and associated Completion Time not met.	B.1	Isolate all main steam lines.	12 hours
	OR		
	B.2	Isolate SJAE.	12 hours
	OR		
	B.3~~.1~~	Be in MODE 3.	12 hours
	~~AND~~		
	~~B.3.2~~	~~Be in MODE 4.~~	~~36 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Two offsite circuits inoperable.	C.1	Declare required feature(s) inoperable when the redundant required feature(s) are inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	AND		
	C.2	Restore one offsite circuit to OPERABLE status.	24 hours
D. One offsite circuit inoperable. AND One required DG inoperable.	D.1	Restore offsite circuit to OPERABLE status.	12 hours
	OR		
	D.2	Restore required DG to OPERABLE status.	12 hours
E. Two required DGs inoperable.	E.1	Restore one required DG to OPERABLE status.	2 hours OR 24 hours if Division 3 DG is inoperable
F. Required Action and Associated Completion Time of Condition A, B, C, D, or E not met.	F.1	Be in MODE 3.	12 hours
	~~AND~~		
	~~F.2~~	~~Be in MODE 4.~~	~~36 hours~~

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources—Operating

LCO 3.8.4 The Division 1, Division 2, Division 3, and Division 4 DC electrical power subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One battery charger on Division 1 or 2 inoperable.	A.1 Restore battery terminal voltage to greater than or equal to the minimum established float voltage.	2 hours
	AND	
	A.2 Verify battery float current ≤ 2 amps.	Once per 12 hours
	AND	
	A.3 Restore battery charger to OPERABLE status.	7 days
B. One battery on Division 1 or 2 inoperable.	B.1 Restore battery to OPERABLE status.	2 hours
C. Division 1 or 2 DC electrical power subsystem inoperable for reasons other than Condition A or B.	C.1 Restore Division 1 and 2 DC electrical power subsystems to OPERABLE status.	2 hours
~~D.~~ E. Division 3 or 4 DC electrical power subsystem inoperable.	~~D.1~~ E.1 Declare High Pressure Core Spray System inoperable.	Immediately
~~E.~~ F. Required Action and associated Completion Time not met. for Condition E	~~E.1~~ F.1 Be in MODE 3.	12 hours
	AND	
	~~E.2~~ F.2 Be in MODE 4.	36 hours
D. Required Action and associated Completion Time for Condition A, B, or C not met.	D.1 Be in MODE 3.	12 hours

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters—Operating

LCO 3.8.7 The Division 1, 2, 3, and 4 inverters, and A and B RPS solenoid bus inverters shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

----------NOTE----------
Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," with any uninterruptible AC bus de-energized.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Division 1 or 2 inverter inoperable.	A.1	Restore Division 1 and 2 inverters to OPERABLE status.	7 days
~~B.~~ C. One or more Division 3 or 4 inverters inoperable.	~~B.1~~ C.1	Declare High Pressure Core Spray System inoperable.	Immediately
~~C.~~ D. One RPS solenoid bus inverter inoperable.	~~C.1.1~~ D.1.1	Transfer RPS bus to alternate power source.	1 hour
	AND		
	~~C.1.2~~ D.1.2	Verify RPS bus supply frequency ≥ 57 Hz.	Once per 8 hours thereafter
	OR		
	~~C.2~~ D.2	De-energize RPS bus.	1 hour

(continued)

B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~D.~~ E. Both RPS solenoid bus inverters inoperable.	~~D.1~~ E.1 De-energize one RPS solenoid bus.	1 hour
~~E.~~ F. Required Action and associated Completion Time not met. for Condition C, D, or E	F.1 ~~E.1~~ Be in MODE 3. AND ~~E.2~~ F.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct inverter voltage, frequency, and alignment to required uninterruptible AC buses and RPS solenoid buses.	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more Division 1 or 2 DC electrical power distribution subsystems inoperable.	C.1 Restore Division 1 and 2 DC electrical power distribution subsystems to OPERABLE status.	2 hours AND 16 hours from discovery of failure to meet LCO
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Be in MODE 3. ~~AND~~ ~~D.2 Be in MODE 4.~~	12 hours ~~36 hours~~
E. One or more Division 3 or 4 AC, DC, or uninterruptible AC bus electrical power distribution subsystems inoperable.	E.1 Declare High Pressure Core Spray System inoperable.	Immediately
F. Two or more divisions with inoperable distribution subsystems that result in a loss of function.	F.1 Enter LCO 3.0.3.	Immediately

ATTACHMENT 3
Mark-up of Technical Specification Bases Changes
(For Information Only)

B 3.3 -233 to B 3.3 -236
B 3.5 -7
B 3.5 -8
B 3.5 -10 to B 3.5 -14a
B 3.6 -4
B 3.6 -5
B 3.6 -36 to B 3.6 -38
B 3.6 -41
B 3.6 -43
B 3.6 -47c
B 3.6 -58
B 3.6 -59
B 3.6 -86 to B 3.6 -88a
B 3.6 -98 to B 3.6 -101a
B 3.6 -130 to B 3.6 -132
B 3.7 -4 to B 3.7 -6
B 3.7 -12 to B 3.7 -16a
B 3.7 -19
B 3.7 -21
B 3.7 -23 to B 3.7 -24a
B 3.8 -12 to B 3.8 -16
B 3.8 -18 B 3.8 -22
B 3.8 -24 B 3.8 -29
B 3.8 -31 B 3.8 -32a
B 3.8 -55 B 3.8 -58
B 3.8 -71b
B 3.8 -72
B 3.8 -73
B 3.8 -85 to B 3.8 -87

BASES

APPLICABILITY (continued)

in MODES 1, 2, and 3, and MODES 4 and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

A.1

If the power monitoring assembly for an inservice power supply (UPS or alternate) is inoperable, or the power monitoring assembly in each inservice power supply is inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore the assembly to OPERABLE status for each inservice power supply. If the inoperable assembly for each inservice power supply cannot be restored to OPERABLE status, the associated power supplies must be removed from service within 1 hour (Required Action A.1). An alternate power supply with OPERABLE assemblies may then be used to power one RPS bus. The 1 hour Completion Time is sufficient for the plant operations personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration or removal from service of the electric power monitoring assemblies.

Alternately, if it is not desired to remove the power supply(s) from service (e.g., as in the case where removing the power supply(s) from service would result in a scram or isolation), Condition B or C, as applicable, must be entered and its Required Actions taken.

In addition to the actions identified in Condition A, if the frequency of the supply to the RPS solenoid bus is ≤ 57 Hz, the OPERABILITY of all Class 1E equipment which could have been subjected to the abnormal frequency on the associated RPS solenoid bus must be demonstrated by the performance of a CHANNEL FUNCTIONAL TEST or CHANNEL CALIBRATION, as required. These tests should be performed within 24 hours of discovering the underfrequency condition.

B.1 ~~and B.2~~

the plant must be brought to a MODE in which overall plant risk is minimized.

If any Required Action and associated Completion Time of Condition A is not met in MODE 1, 2, or 3, ~~a plant shutdown must be performed. This places the plant in a condition where minimal equipment, powered through the inoperable RPS~~

(continued)

BASES

ACTIONS

B.1 ~~and B.2~~ (continued)

~~electric power monitoring assembly(s), is required and ensures that the safety function of the RPS (e.g., scram of control rods) is not required.~~ The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours ~~and in MODE 4 within 36 hours.~~ The allowed Completion Time~~s~~ ~~are~~ is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Insert 1

C.1

If any Required Action and associated Completion Time of Condition A is not met in MODE 4 or 5, with any control rod withdrawn from a core cell containing one or more fuel assemblies, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies (Required Action C.1). This Required Action results in the least reactive condition for the reactor core and ensures that the safety function of the RPS (e.g., scram of control rods) is not required.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS bus will not jeopardize steady state power operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1 (continued)

Surveillance. The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. ~~2~~ 3).

SR 3.3.8.2.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.2.3

Performance of a system functional test demonstrates a required system actuation (simulated or actual) signal. The logic of the system will automatically trip open the associated power monitoring assembly circuit breaker. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.3 (continued)

Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance.

REFERENCES

1. USAR, Section 8.3.1.1.3.1.

Insert 2

3. ~~2.~~ NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."

BASES

ACTIONS (continued)

C.1

With two ECCS injection subsystems inoperable or one ECCS injection and one ECCS spray subsystem inoperable, at least one ECCS injection/spray subsystem must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced in this Condition because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since the ECCS availability is reduced relative to Condition A, a more restrictive Completion Time is imposed. The 72 hour Completion Time is based on a reliability study, as provided in Reference 12.

D.1 ~~and D.2~~

If any Required Action and associated Completion Time of Condition A, B, or C 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 ~~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.

overall plant risk is minimized.

Insert 1

is

E.1

14

The LCO requires seven ADS valves to be OPERABLE to provide the ADS function. Reference ~~13~~ contains the results of an analysis that evaluated the effect of one ADS valve being out of service. Per this analysis, operation of only six 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 (Ref. 12) and has been found to be acceptable through operating experience.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to one inoperable ADS valve, adequate core cooling is ensured by the OPERABILITY of HPCS and the remaining low pressure ECCS injection/spray subsystems. However, the 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 portion of a high pressure (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 injection/spray subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study (Ref. 12) and has been found to be acceptable through operating experience.

G.1 ~~and G.2~~

If any Required Action and associated Completion Time of Condition E or F are not met or if two or more ADS valves are inoperable, the plant must be brought to a ~~condition~~ MODE in which the ~~LCO does not apply~~ overall plant risk is minimized. 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.~~ Insert 1 The allowed Completion Times ~~are~~ is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

When multiple ECCS subsystems are inoperable, as stated in Condition H, the plant is in a degraded condition not specifically justified for continued operation, and may be in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.2 (continued)

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 accumulator supply pressure is ≥ 140 psig assures adequate air pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The designed pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator, at least two valve actuations can occur with the drywell at 70% of design pressure (Ref. ~~14~~ 15). 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 140 psig is provided by the Instrument Air System. The 31 day Frequency takes into consideration administrative control over operation of the Instrument Air System and alarms for low air pressure.

With regard to ADS accumulator supply pressure values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Ref. ~~16~~ 17).

SR 3.5.1.4

The performance requirements of the 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 ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of 10 CFR 50.46 (Ref. 10).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.4 (continued)

The pump flow rates are verified with a pump differential pressure that is sufficient to overcome the RPV pressure expected during a LOCA. The 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 LOCAs. These values may be established during pre-operational testing. The Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements.

With regard to pump flow rates and differential pressures values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Refs. ~~17, 18, 19~~ 18, 19, 20).

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance test verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCS, LPCS, 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 Surveillance also ensures that the HPCS 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 RCIC storage tank to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform this 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, which is based on the refueling cycle. Therefore, the Frequency

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.5 (continued)

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.

SR 3.5.1.6

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 3.5.1.7 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 this 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, 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 3.5.1.7

A manual actuation of each required ADS valve (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to verify that the valve is functioning properly. This SR can be demonstrated by one of two methods. If performed by Method 1, plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements (Ref. ~~21~~ 22), 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7 (continued)

Conditions for testing and provides a reasonable time to complete the SR. If performed by Method 2, valve OPERABILITY has been demonstrated for all installed ADS valves based upon the successful operations of a test sample of S/RVs.

1. Manual actuation of the ADS valve, with verification of the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow (e.g., tailpipe temperature or acoustic monitoring). Adequate reactor steam pressure must be available to perform this test to avoid damaging the valve. 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 test. Adequate pressure at which this test is to be performed is consistent with the pressure recommended by the valve manufacturer.

2. The sample population of S/RVs tested to satisfy SR 3.4.4.1 will also be stroked in the relief mode during "as-found" testing to verify proper operation of the S/RV. The successful performance of the test sample of S/RVs provides reasonable assurance that all ADS valves will perform in a similar fashion. After the S/RVs are replaced, the relief-mode actuator of the newly-installed S/RVs will be uncoupled from the S/RV stem, and cycled to ensure that no damage has occurred to the S/RV during transportation and installation. Following cycling, the relief-mode actuator is recoupled and the proper positioning of the stem nut is independently verified. This verifies that each replaced S/RV will properly perform its intended function.

SR 3.5.1.6 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 STAGGERED TEST BASIS Frequency ensures that both solenoids for each ADS valve relief-mode actuator are alternately tested. The Frequency of the required relief-mode actuator testing is based on the tests required by ASME OM, Part 1, (Ref. ~~21~~) as implemented by the Inservice Testing Program of Specification 5.5.6. The testing Frequency required by the Inservice Testing Program is based on operating experience and valve performance. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. 22

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.8

This SR ensures that the ECCS RESPONSE TIMES are within limits for each of the ECCS injection and spray subsystems. The response time limits (i.e., ≤42 seconds for the LPCI subsystems, ≤41 seconds for the LPCS subsystem, and ≤27 seconds for the HPCS system) are specified in applicable surveillance test procedures. This SR is modified by a Note which identifies that the associated ECCS actuation instrumentation is not required to be response time tested. This is supported by Reference ~~15~~ 16.

Response time testing of the remaining subsystem components is required. However, of the remaining subsystem components, the time for each ECCS pump to reach rated speed is not directly measured in the response time tests. The time(s) for the ECCS pumps to reach rated speed is bounded, in all cases, by the time(s) for the ECCS injection valve(s) to reach the full-open position. Plant-specific calculations show that all ECCS motor start times at rated voltage are less than two seconds. In addition, these calculations show that under degraded voltage conditions, the time to rated speed is less than five seconds.

ECCS RESPONSE TIME tests are conducted every 24 months. The 24 month Frequency is based on the need to perform this 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, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

With regard to ECCS RESPONSE TIME values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~20~~ 21).

(continued)

BASES

REFERENCES

1. USAR, Section 6.3.2.2.3.

2. USAR, Section 6.3.2.2.4.

3. USAR, Section 6.3.2.2.1.

4. USAR, Section 6.3.2.2.2.

5. USAR, Section 15.2.8.

6. USAR, Section 15.6.4.

7. USAR, Section 15.6.5.

8. 10 CFR 50, Appendix K.

9. USAR, Section 6.3.3.

10. 10 CFR 50.46.

11. USAR, Section 6.3.3.3.

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

Insert 2

14. ~~13.~~ USAR, Table 6.3-8.

15. ~~14.~~ USAR, Section 7.3.1.1.1.4.

16. ~~15.~~ NEDO-32291-A, "System Analyses for Elimination of Selected Response Time Testing Requirements," January 1994.

17. ~~16.~~ Calculation IP-0-0044.

18. ~~17.~~ Calculations 01HP09/10/11, IP-C-0042.

19. ~~18.~~ Calculations 01LP08/11/14, IP-C-0043.

20. ~~19.~~ Calculations 01RH19/20/23/24, IP-C-0041.

21. ~~20.~~ Calculation IP-0-0024.

22. ~~21.~~ ASME/ANSI OM-1987, Operation and Maintenance of Nuclear Power Plants, Part 1.

BASES

ACTIONS

A.1 (continued)

time to correct the problem that is commensurate with the importance of maintaining primary containment OPERABILITY during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring primary containment OPERABILITY) occurring during periods where primary containment is inoperable is minimal.

B.1 ~~and B.2~~

overall plant risk is minimized.

If primary containment 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.

is

Insert 1

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. Failure to meet air lock leakage testing (SR 3.6.1.2.1), secondary containment bypass leakage (SR 3.6.1.3.8), resilient seal primary containment purge valve leakage testing (SR 3.6.1.3.5), main steam isolation valve leakage (SR 3.6.1.3.9), or hydrostatically tested valve leakage (SR 3.6.1.3.10) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program. As left leakage prior to the first startup after performing a required leakage test is required to be $\leq 0.6\ L_a$ for combined Type B and C leakage, and $\leq 0.75\ L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

This Surveillance is modified by a Note that requires the leakage rate results of SR 3.6.1.1.2 for the Primary Containment Hydrogen Recombiner System (each loop) to be included in determining compliance with required limits. This can be accomplished either by having the loops in service during the ILRT, or if the loop is not in service during the ILRT, by separately measuring the leakage and including it in the measured ILRT results.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.1.1 (continued)

With regard to leakage rate values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~7~~ 8).

SR 3.6.1.1.2

With respect to primary containment integrated leakage rate testing, the primary containment hydrogen recombiners (located outside the primary containment) are considered extensions of the primary containment boundary. This requires the smaller of the leakage from the PCIVs that isolate the primary containment hydrogen recombiner, or from the piping boundary outside containment, to be included in the ILRT results. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

With regard to leakage rate values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~7~~ 8).

REFERENCES

1. USAR, Section 6.2.

2. USAR, Section 15.6.5.

3. 10 CFR 50, Appendix J, Option B.

4. USAR, Section 6.2.1.

Insert 2

6. ~~5.~~ NEI 94-01, Revision 0, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J."

7. ~~6.~~ ANSI/ANS-56.8-1994, "American National Standard for Containment System Leakage Testing Requirement."

8. ~~7.~~ Calculation IP-0-0056.

BASES

APPLICABLE SAFETY ANALYSES (continued)

LLS S/RVs are specified, all five LLS S/RVs do not operate in any DBA analysis.

LLS valves satisfy Criterion 3 of the NRC Policy Statement.

LCO

Five LLS valves are required to be OPERABLE to satisfy the assumptions of the safety analysis (Ref. 1). The requirements of this LCO are applicable to the mechanical and electrical/pneumatic capability of the LLS valves to function for controlling the opening and closing of the S/RVs.

APPLICABILITY

In MODES 1, 2, and 3, an event could cause pressurization of the reactor and opening of S/RVs. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the LLS valves OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one LLS valve inoperable, the remaining OPERABLE LLS valves are adequate to perform the designed function. However, the overall reliability is reduced. The 14 day Completion Time takes into account the redundant capability afforded by the remaining LLS S/RVs and the low probability of an event in which the remaining LLS S/RV capability would be inadequate.

B.1 ~~and B.2~~

If

~~If two or more LLS valves are inoperable or if~~ the inoperable LLS valve cannot be restored to OPERABLE status within the required 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

overall plant risk is minimized.

Insert 1

is

(continued)

BASES

ACTIONS

B.1 ~~and B.2~~ (continued)

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

Insert 2

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

A manual actuation of each required LLS valve (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to verify that the valve is functioning properly. This SR can be demonstrated by one of two methods. If performed by Method 1, plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements (Ref. ~~2~~ 3), 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 for testing and provides a reasonable time to complete the SR. If performed by Method 2, valve OPERABILITY has been demonstrated for all installed LLS valves based upon the successful operation of a test sample of S/RVs.

1. Manual actuation of the LLS valve, with verification of the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow (e.g., tailpipe temperature or acoustic monitoring). Adequate reactor steam pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the LLS valves divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this test. Adequate pressure at which this test is to be performed is consistent with the pressure recommended by the valve manufacturer.

2. The sample population of S/RVs tested to satisfy SR 3.4.4.1 will also be stroked in the relief mode during "as-found" testing to verify proper operation of the S/RV. The successful performance of the test sample of S/RVs provides reasonable assurance that all LLS valves will perform in similar fashion. After the S/RVs are replaced, the relief-mode actuator of the newly-installed S/RVs will be uncoupled from the S/RV stem, and cycled to ensure that no damage has occurred to the S/RV during transportation and installation. Following cycling, the relief-mode actuator is recoupled and the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1 (continued)

proper positioning of the stem nut is independently verified. This verifies that each replaced S/RV will properly perform its intended function.

The Frequency of the required relief-mode actuator testing is based on the tests required by ASME OM Part 1 (Ref. ~~2~~ 3), as implemented by the Inservice Testing Program of Specification 5.5.6. The testing Frequency required by the Inservice Testing Program is based on operating experience and valve performance. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.6.2

The LLS designed S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify that the mechanical portions (i.e., solenoids) of the automatic LLS function operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.5.4 overlaps this SR to provide complete testing of the safety function.

The 24 month Frequency is based on the need to perform this 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 these components usually pass the Surveillance. 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 a reactor pressure vessel pressure blowdown.

REFERENCES

1. USAR, Section 5.2.2.2.3.

Insert 3

3. ~~2.~~ ASME/ANSI OM-1987, Operation and Maintenance of Nuclear Power Plants, Part 1.

BASES

ACTIONS (continued)

B.1

With two RHR containment spray subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this Condition, there is a substantial loss of the drywell bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to remove heat from primary containment are available.

C.1 ~~and C.2~~

If the inoperable RHR containment spray subsystem cannot be restored to OPERABLE status within the required 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~~ is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

overall plant risk is minimized

Insert 1

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR containment spray mode flow path provides assurance that the proper flow paths will exist for system 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 to locking, sealing, or securing. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency of this SR is justified because the valves are operated under procedural control and because improper valve position would affect only a single subsystem. This Frequency has been shown to be acceptable based on operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.3 (continued)

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

SR 3.6.1.7.4

This Surveillance is performed following activites that could result in nozzle blockage to verify that the spray nozzles are not obstructed and that flow will be provided when required. Such activities may include a loss of foreign material control (of if it cannot be assured), following a major configuration change, or following an inadvertent actuation of containment spray. This Surveillance is normally performed by an air or smoke flow test. The Frequency is adequate due to the passive nozzle design and its normally dry state and has been shown to be acceptable through operating experience.

REFERENCES

1. USAR, Section 6.2.1.1.5.

Insert 2

3. ~~2.~~ ASME, Boiler and Pressure Vessel Code, Section XI.

4. ~~3.~~ USAR, Section 5.4.7

BASES

ACTIONS (continued)

C.1 ~~and C.2~~

If the inoperable FWLCS subsystem cannot be restored to OPERABLE status within the required 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~~ is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

overall plant risk is minimized

Insert 1

SURVEILLANCE REQUIREMENTS

SR 3.6.1.9.1

A system functional test of each FWLCS subsystem is performed to ensure that each FWLCS subsystem will operate through its operating sequence. This includes verifying automatic positioning of valves and operation of each interlock, and that the necessary check valves open. Adequacy of the associated RHR pumps to deliver FWLCS flow rates required to meet the assumptions made in the supporting analyses concurrent with other modes was demonstrated during acceptance testing of the system after installation. Periodic verification of the capabilities of the RHR pumps is performed under SR 3.5.1.4.

The 24 month Frequency is based on the need to perform this 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.

REFERENCES

1. USAR, Section 15.6.5.

Insert 2

BASES

ACTIONS (continued)

B.1 ~~and B.2~~

If the Required Action and required Completion Time of Condition A cannot be met ~~or if two RHR suppression pool cooling subsystems are inoperable~~, 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.

overall plant risk is minimized

Insert 1

is

Insert 2

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual, power operated, and automatic valves, in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists for system 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 being locked, sealed, or secured. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable, since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the subsystem is a manually initiated system. This Frequency has been shown to be acceptable, based on operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.2.3.2

Verifying each RHR pump develops a flow rate ≥ 4550 gpm, with flow through the associated heat exchanger to the suppression pool, ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by ASME Section XI (Ref. ~~2~~ 3). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

With regard to RHR pump flow rate values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties for implementation in the associated plant procedures. (Ref. ~~4~~ 5).

REFERENCES

1. USAR, Section 6.2.

3. ~~2~~. ASME, Boiler and Pressure Vessel Code, Section XI.

4. ~~3~~. USAR, Section 5.4.7.

5. ~~4~~. Calculations 01RH20/25 and IP-C-0041.

Insert 3

ACTIONS

A.1 (continued)

containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1 ~~and B.2~~

overall plant risk is minimized.

If the secondary containment cannot be restored to OPERABLE status within the required 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.

Insert 1

is

C.2

C.1, and ~~C.3~~

Movement of recently irradiated fuel assemblies in the primary or secondary containment and OPDRVs can be postulated to cause fission product release to the secondary containment. In such cases, the secondary containment is the only barrier to release of fission products to the environment. Movement of recently irradiated fuel assemblies must be immediately suspended if the secondary containment is inoperable.

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving recently irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

movement of recently irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. The 24 hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations during the applicable MODES and the low probability of a DBA occurring between surveillances.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal secondary containment vacuum condition.

With regard to secondary containment vacuum values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~3~~ 4).

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that secondary containment equipment hatches and access doors are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary containment will not occur. In this application the term "sealed" has no connotation of leak tightness. Maintaining secondary containment OPERABILITY requires verifying one door in the access opening is closed, except when the access opening is being used for entry and exit. The 31 day Frequency for these SRs has been shown to be adequate based on operating experience, and is considered adequate in view of the other controls on secondary containment access openings.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.1.4 and SR 3.6.4.1.5

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. To ensure that all fission products are treated, SR 3.6.4.1.4 verifies that the SGT System will rapidly establish and maintain a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary. This is confirmed by demonstrating that one SGT subsystem will draw down the secondary containment to ≥ 0.25 inches of vacuum water gauge within the required time.

Specifically, the required drawdown time limit is based on ensuring that the SGT system will draw down the secondary containment pressure to ≥ 0.25 inches of vacuum water gauge within 12 minutes (i.e., 10 minutes from start of gap release which occurs 2 minutes after LOCA initiation) under LOCA conditions. Typically, however, the conditions under which drawdown testing is performed pursuant to SR 3.6.4.1.4 are different than those assumed for LOCA conditions. For this reason, and because test results are dependent on or influenced by certain plant and/or atmospheric conditions that may be in effect at the time testing is performed, it is necessary to adjust the test acceptance criteria (i.e., the required drawdown time) to account for such test conditions. Conditions or factors that may impact the test results include wind speed, whether the turbine building ventilation system is running, and whether the containment equipment hatch is open (when the test is performed during plant shutdown/outage conditions). The acceptance criteria for the drawdown test are thus based on a computer model (Ref. 6), verified by actual performance of drawdown tests, in which the drawdown time determined for accident conditions is adjusted to account for performance of the test during normal but certain plant conditions. The test acceptance criteria are specified in the applicable plant test procedure(s). Since the drawdown time is dependent upon secondary containment integrity, the drawdown requirement cannot be met if the secondary containment boundary is not intact.

SR 3.6.4.1.5 demonstrates that each SGT subsystem can maintain ≥ 0.25 inches of vacuum water gauge for 1 hour at a flow rate ≤ 4400 acfm. The 1-hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. Therefore, the tests required per SR 3.6.4.1.4 and SR 3.6.4.1.5 are performed to ensure secondary containment boundary integrity. Since these SRs are secondary containment tests, they need not be performed with each SGT subsystem and an inoperable SGT subsystem does not result in this SR being not met. The SGT subsystems are tested on a STAGGERED TEST BASIS, however, to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. Operating experience has

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.4 and SR 3.6.4.1.5 (continued)

shown these components usually pass the Surveillance. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

With regard to drawdown time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Refs. ~~4, 5~~ 5, 6).

REFERENCES

1. USAR, Section 15.6.5.

2. USAR, Section 15.7.4.

Insert 2

4. ~~3.~~ Calculation IP-0-0082.

5. ~~4.~~ Calculation IP-0-0083.

6. ~~5.~~ Calculation IP-0-0084.

7. ~~6.~~ Calculation 3C10-1079-001.

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the SGT System OPERABLE is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs) or during movement of recently irradiated fuel assemblies (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours) in the primary or secondary containment.

ACTIONS

A.1

With one SGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE SGT subsystem is adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single failure in the OPERABLE subsystem could result in the radioactivity release control function not being adequately performed. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SGT subsystem and the low probability of a DBA occurring during this period.

B.1 ~~and B.2~~

If the SGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, 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 Time~~s~~ ~~are~~ is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

overall plant risk is minimized.

Insert 1

C.1, C.2.1 and C.2.2

During movement of recently irradiated fuel assemblies in the primary or secondary containment or during OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE SGT subsystem should be immediately placed in operation. This Required Action ensures that the remaining subsystem is OPERABLE,

(continued)

ACTIONS

C.1, C.2.1 and C.2.2 (continued)

that no failures that could prevent automatic actuation have occurred, and that any other failure would be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing radioactive material to the secondary containment, thus placing the unit in a Condition that minimizes risk. If applicable, movement of recently irradiated fuel assemblies must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. This action should be chosen if the OPDRVs could be impacted by a loss of offsite power. Action must continue until OPDRVs are suspended.

The Required Actions of Condition C have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of recently irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

D.1

If both SGT subsystems are inoperable in MODE 1, 2, or 3, the SGT System may not be capable of supporting the required radioactivity release control function. ~~Therefore, LCO 3.0.3 must be entered immediately.~~ Insert 2

E.1 and E.2

When two SGT subsystems are inoperable, if applicable, movement of recently irradiated fuel assemblies in the primary and secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGT subsystem from the main control room for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

With regard to operating time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~9~~ 10).

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber bypass leakage and efficiency, minimum system flow rate, combined HEPA filter and charcoal adsorber pressure drop, and heater dissipation. The frequencies for performing the SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 4) and include testing initially, after 720 hours of system operation, once per 24 months, and following painting, fire, or chemical release in any ventilation zone communicating with the system. The laboratory test results will be

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.2 (continued)

verified to be within limits within 31 days of removal of the sample from the system. Additional information is discussed in detail in the VFTP.

With regard to filter testing values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~10~~ 11).

SR 3.6.4.3.3

This SR requires verification that each SGT subsystem automatically starts upon receipt of an actual or simulated initiation signal.

The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.4.3.4

This SR requires verification that the SGT filter cooling bypass damper can be opened and the fan started. This ensures that the ventilation mode of SGT System operation is available. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 41.
2. USAR, Section 6.2.3.
3. USAR, Section 15.6.5.
4. Regulatory Guide 1.52.
5. USAR, Section 6.5.1.
6. USAR, Section 15.6.4.
7. USAR Appendix A.
8. ASME/ANSI N510-1980.

Insert 3

10. ~~9.~~ Calculation IP-0-0086.
11. ~~10.~~ Calculation IP-0-0087.

ACTIONS

A.1 (continued)

A Note has been added to provide clarification that separate Condition entry is allowed for each vacuum relief subsystem not closed.

B.1

With one drywell post-LOCA vacuum relief subsystem inoperable for reasons other than Condition A, the inoperable subsystem must be restored to OPERABLE status within 30 days. In these Conditions, the remaining OPERABLE vacuum relief subsystems are adequate to perform the depressurization mitigation function since three 10-inch lines remain available. The 30 day Completion Time takes into account the redundant capability afforded by the remaining subsystems, a reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

C.1

With two or more drywell post-LOCA vacuum relief subsystems inoperable for reasons other than Condition A, the inoperable subsystems must be restored to OPERABLE status within 72 hours. The 72 hour Completion Time takes into account a reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

D.1 and D.2

If the inoperable drywell post-LOCA vacuum relief subsystem(s) cannot be closed ~~or restored to OPERABLE status~~ within the required 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

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

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

Insert 1

SURVEILLANCE REQUIREMENTS

SR 3.6.5.6.1

Each drywell post-LOCA vacuum relief valve is verified to be closed (except when being tested in accordance with SR 3.6.5.6.2 and SR 3.6.5.6.3 or when the drywell post-LOCA vacuum relief valves are performing their intended design function) to ensure that this potential large drywell bypass leakage path is not present. This Surveillance is normally performed by observing the drywell post-LOCA vacuum relief valve position indication. The 7 day Frequency is based on engineering judgment, is considered adequate in view of other indications of drywell post-LOCA vacuum relief valve status available to the plant personnel, and has been shown to be acceptable through operating experience.

Two Notes are added to this SR. The first Note allows drywell post-LOCA vacuum relief valves opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening drywell post-LOCA vacuum relief valves are controlled by plant procedures and do not represent inoperable drywell post-LOCA vacuum relief valves. A second Note is included to clarify that valves open due to an actual differential pressure, are not considered as failing this SR.

SR 3.6.5.6.2

Each drywell post-LOCA vacuum relief valve must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This provides assurance that the safety analysis assumptions are valid. A 31 day Frequency was chosen to provide additional assurance that the drywell post-LOCA vacuum relief valves are OPERABLE.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.5.6.3

Verification of the drywell post-LOCA vacuum relief valve opening differential pressure is necessary to ensure that the safety analysis assumptions of ≤ 0.2 psid for drywell vacuum relief are valid. The safety analysis assumes that the drywell post-LOCA vacuum relief valves will start opening when the dry well pressure is approximately 0.2 psid less than the containment and will be fully open when this differential pressure is 0.5 psid. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for violating the drywell boundary. Operating experience has shown these components usually pass the Surveillance, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 6.2.

Insert 2

BASES (continued)

ACTIONS

A.1

If the UHS is inoperable (i.e., the UHS water volume is not within the limit), action must be taken to restore the inoperable UHS to OPERABLE status within 90 days. The 90 day Completion Time is reasonable considering the time required to restore the required UHS volume, the margin contained in the available heat removal capacity, and the low probability of a DBA occurring during this period.

B.1

If the Division 1 or 2 SX subsystem is inoperable, it must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE Division 1 or 2 SX subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE Division 1 or 2 SX subsystem could result in loss of the SX function. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

The Required Action is modified by two Notes indicating that the applicable Conditions of LCO 3.8.1, "AC Sources—Operating," and LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," be entered and the Required Actions taken if the inoperable SX subsystem results in an inoperable DG or RHR shutdown cooling subsystem, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

Insert 1 → D

D ~~C~~.1 and ~~C~~.2

If the Required Action and associated Completion Time of Condition A or B are not met, or both Division 1 and 2 SX subsystems are inoperable, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies UHS water volume is ≥ 593 acre-feet (excluding sediment). The Surveillance Frequency is in accordance with UHS Erosion, Sediment Monitoring and Dredging Program.

With regard to UHS water volume values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~8~~ 9).

SR 3.7.1.2

Verifying the correct alignment for each manual, power operated, and automatic valve in each Division 1 and 2 SX subsystem flow path provides assurance that the proper flow paths will exist for Division 1 and 2 SX subsystem 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 is also allowed to be in the nonaccident position and yet considered in the correct position, provided it can be automatically realigned to its accident position within the required 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.2 (continued)

Isolation of the SX subsystem to components or systems does not necessarily affect the OPERABILITY of the associated SX subsystem. As such, when all SX pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the associated SX subsystem needs to be evaluated to determine if it is still OPERABLE. Alternatively, it is acceptable and conservative to declare an SX subsystem inoperable when a branch connection is isolated or a supported ventilation system is inoperable.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.1.3

This SR verifies that the automatic isolation valves of the Division 1 and 2 SX subsystems will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This is demonstrated by use of an actual or simulated initiation signal and is performed with the plant shut down. This SR also verifies the automatic start capability of the SX pump in each subsystem.
Operating experience has shown that these components usually pass the SR. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.27, Revision 2, January 1976.

2. USAR, Section 9.2.1.2.

3. USAR, Table 9.2-3.

4. USAR, Section 6.2.1.1.3.3.

5. USAR, Chapter 15.

6. USAR, Section 6.2.2.3.

7. USAR, Table 6.2-2.

Insert 2 → 9. ~~8.~~ Calculation IP-0-0095.

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the Control Room Ventilation System must be OPERABLE to control operator exposure during and following a DBA, since the DBA could lead to a fission product release.

In MODES 4 and 5, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the Control Room Ventilation System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

a. During operations with a potential for draining the reactor vessel (OPDRVs);

b. During CORE ALTERATIONS; and

c. During movement of irradiated fuel assemblies in the primary or secondary containment.

ACTIONS

A.1

With one Control Room Ventilation subsystem inoperable, the inoperable Control Room Ventilation subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE Control Room Ventilation subsystem is adequate to perform control room radiation protection. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in loss of Control Room Ventilation System function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and that the remaining subsystem can provide the required capabilities.

B.1 ~~and B.2~~

In MODE 1, 2, or 3, if the inoperable Control Room Ventilation subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes overall plant risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours ~~and in MODE 4 within 36 hours~~. Insert 1 The allowed

(continued)

ACTIONS

B.1 ~~and B.2~~ (continued)

Completion Time~~s~~ ~~are~~ is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1, C.2.1, C.2.2, and C.2.3

The Required Actions of Condition C are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the primary or secondary containment, during CORE ALTERATIONS, or during OPDRVs, if the inoperable Control Room Ventilation subsystem cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE Control Room Ventilation subsystem may be placed in the high radiation mode. This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the primary and secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

(continued)

ACTIONS (continued)

D.1

If both Control Room Ventilation subsystems are inoperable in MODE 1, 2, or 3, the Control Room Ventilation System may not be capable of performing the intended function and the unit is in a condition outside of the accident analyses. ~~Therefore, LCO 3.0.3 must be entered immediately.~~ Insert 2

E.1, E.2, and E.3

During movement of irradiated fuel assemblies in the primary or secondary containment, during CORE ALTERATIONS, or during OPDRVs, with two Control Room Ventilation subsystems inoperable, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require treatment of the control room air. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the primary and secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. If applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1 and SR 3.7.3.2

This SR verifies that a subsystem in a standby mode starts on demand and continues to operate. Standby systems should be checked periodically to ensure that they start and function properly. As the environmental and normal operating conditions of this system are not severe, testing each subsystem once every month provides an adequate check on this system. Monthly heater operation dries out any moisture accumulated in the charcoal from humidity in the ambient air. The Makeup Filter System must be operated from the main control room for ≥ 10 continuous hours with the heaters energized. The Recirculation Filter System (without heaters) need only be operated for ≥ 15 minutes to demonstrate the function of the system. Furthermore, the 31 day Frequency is based on the known reliability of the equipment and the two subsystem redundancy available.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1 and SR 3.7.3.2 (continued)

With regard to subsystem operation time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~8, 9~~ 9, 10).

SR 3.7.3.3

This SR verifies that the required Control Room Ventilation System testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber bypass leakage and efficiency, minimum system flow rate (scfm), combined HEPA filter and charcoal adsorber pressure drop, and heater dissipation. The frequencies for performing the Control Room Ventilation System filter tests are in accordance with Regulatory Guide 1.52 (Ref. ~~4~~ 7) and include testing initially, after 720 hours of system operation, once per 24 months, and following painting, fire, or chemical release in any ventilation zone communicating with the system. The laboratory test results will be verified to be within limits within 31 days of removal of the sample from the system. Additional information is discussed in detail in the VFTP.

With regard to filter testing parameter values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Refs. ~~10, 11~~ 11, 12).

SR 3.7.3.4

This SR verifies that each Control Room Ventilation subsystem starts and operates on an actual or simulated high radiation initiation signal. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.3.5

This SR verifies the integrity of the negative pressure portions of the Control Room Ventilation System ductwork located outside the main control room habitability boundary between fan OVC04CA(B) and isolation dampers OVC03YA(B) inclusive and fire dampers OVC042YA(E), OVC042YB(F), OVC042YC(G), and OVC042YD(H). In addition, the integrity of the recirculation filter housing flexible connection to fan OVC03A(B) must be verified. This testing ensures that the inleakage through the negative pressure portion of the Control Room Ventilation System remains within the design basis accident analysis basis. This inleakage would be filtered by the Control Room Ventilation System recirculation filters. An additional allowance of 144 cfm of unfiltered inleakage is also considered in the design basis accident analysis. Operating experience has shown that these components usually pass the SR. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

With regard to inleakage values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Ref. ~~12~~ 13).

SR 3.7.3.6

This SR verifies the integrity of the control room enclosure and the assumed inleakage rates of potentially contaminated air. The control room positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify proper function of the Control Room Ventilation System. During the high radiation mode of operation, the Control Room Ventilation System is designed to slightly pressurize the control room to ≥ 1/8 inches water gauge positive pressure with respect to adjacent areas to prevent unfiltered inleakage. The Control Room Ventilation System is designed to maintain this positive pressure at a flow rate of ≤ 3000 scfm to the control room in the high radiation mode. The Frequency of 24 months on a STAGGERED TEST BASIS is consistent with the refueling cycle and other filtration system SRs.

With regard to control room positive pressure values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, (Ref. ~~13~~ 14).

(continued)

BASES

REFERENCES

1. USAR, Section 6.5.1.

2. USAR, Section 9.4.1.

3. USAR, Chapter 6.

4. USAR, Chapter 15.

Insert 3

6. ~~5.~~ USAR, Appendix A.

7. ~~6.~~ Regulatory Guide 1.52, Revision 2, March 1978.

8. ~~7.~~ ASME/ANSI N510-1980.

9. ~~8.~~ Calculation IP-0-0096.

10. ~~9.~~ Calculation IP-0-0097.

11. ~~10.~~ Calculation IP-0-0098.

12. ~~11.~~ Calculation IP-0-0099.

13. ~~12.~~ Calculation IP-0-0100.

14. ~~13.~~ Calculation IP-0-0101.

BASES (continued)

ACTIONS

A.1

With one control room AC subsystem inoperable, the inoperable control room AC subsystem must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE control room AC subsystem is adequate to perform the control room air conditioning function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in loss of the control room air conditioning function. The 30 day Completion Time is based on the low probability of an event occurring requiring Control Room Ventilation System operation in the high radiation mode, the consideration that the remaining subsystem can provide the required protection, and the availability of alternate cooling methods.

B.1 and B.2

If both control room AC subsystems are inoperable, the Control Room AC System may not be capable of performing its intended function. Therefore, the control room area temperature is required to be monitored to ensure that temperature is being maintained low enough that equipment in the control room is not adversely affected. With the control room temperature being maintained within the temperature limit, 7 days is allowed to restore a control room AC subsystem to OPERABLE status. This Completion Time is reasonable considering that the control room temperature is being maintained within limits, the low probability of an event occurring requiring control room isolation, and the availability of alternate cooling methods.

C.1 ~~and C.2~~

In MODE 1, 2, or 3, if the control room area temperature cannot be maintained ≤ 86°F or if the inoperable control room AC subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes overall plant risk. To achieve this status the unit must be placed in at least MODE 3 within 12 hours ~~and in MODE 4 within 36 hours~~. Insert 1 The allowed Completion Times ~~are~~ is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

BASES

ACTIONS

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

During movement of irradiated fuel assemblies in the primary or secondary containment, during CORE ALTERATIONS, or during OPDRVs, if the Required Action and associated Completion Time of Condition B is not met, action must be taken to immediately suspend activities that present a potential for releasing radioactivity that might require operation of the Control Room Ventilation System in the high radiation mode. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and handling of irradiated fuel in the primary and secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR verifies that the heat removal capability of the system is sufficient to remove the control room heat load assumed in the safety analysis. The SR consists of a combination of testing and calculation. The 24 month Frequency is appropriate since significant degradation of the Control Room AC System is not expected over this time period.

With regard to heat removal capability values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~3~~ 4).

REFERENCES

1. USAR, Section 6.4.

2. USAR, Section 9.4.1.

Insert 2

4. ~~3~~. Calculation IP-0-0102.

BASES (continued)

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser Offgas System. This occurs during MODE 1, and during MODES 2 and 3 with any main steam line not isolated and the SJAE in operation. In MODES 4 and 5, steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72 hour Completion Time is reasonable, based on engineering judgment considering the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the low probability of a Main Condenser Offgas System rupture occurring.

B.1, B.2, and B.3 ~~B.3.1, and B.3.2~~

If the radioactivity rate is not restored to within the limits within the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain valve in each drain line is closed. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging unit systems.

An alternative to Required Actions B.1 and B.2 is to place the unit in a MODE in which the ~~LCO does not apply.~~ overall plant risk is minimized. To

(continued)

BASES

ACTIONS

B.1, B.2, and B.3 ~~B.3.1, and B.3.2~~ (continued)

achieve this status, the unit must be placed in at least MODE 3 within 12 hours ~~and in MODE 4 within 36 hours~~. Insert 1 The allowed Completion Times is ~~are~~ reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1 and SR 3.7.5.2

SR 3.7.5.2, on a 31 day Frequency, requires an isotopic analysis of an offgas sample to ensure that the required limits are satisfied. The noble gases to be sampled are 5 Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88 (Ref. 4). If the measured release rate of radioactivity increases significantly (by ≥ 50% after correcting for expected increases due to changes in THERMAL POWER), an isotopic analysis is also performed within 4 hours after the increase is noted, as required by SR 3.7.5.1, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. The required isotopic analysis is intended to support determination of the cause for the increase in offgas radiation release rates, such as the onset of leakage from a fuel pin(s). However, there are certain evolutions (e.g., swapping of the steam jet air ejectors and regeneration of the offgas system desiccant dryers) which are known to result in a predictable and temporary increase in the indicated offgas radioactivity release rate. These indicated increases in offgas radioactivity release rates can be caused solely by increases in offgas flow. Since these increases are due to an evolution(s) known to cause such an increase and not due to an actual increase in the "nominal steady state fission gas release rate," isotopic analysis of an offgas sample is not required for these evolutions. In any of these cases, it is prudent to ensure that the offgas radiation level (radioactivity release rate) returns to previous or expected levels within four hours or as soon as possible following the evolution. This will confirm that there are no other causes for the increase in the radioactivity release rate indication. The 31 day Frequency is adequate in view of other instrumentation that continuously monitor the offgas, and is acceptable based on operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1 and SR 3.7.5.2 (continued)

SR 3.7.5.2 is modified by a Note indicating that the SR is not required to be performed until 31 days after any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Main Condenser Offgas System at significant rates.

With regard to radioactivity rate values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~5~~ 6).

REFERENCES

1. USAR, Section 15.7.1.

2. NUREG-0800.

3. 10 CFR 100.

Insert 2

5. ~~4~~. NEDE-24810, "Station Nuclear Engineering," Volume 1A.

6. ~~5~~. Calculation IP-0-0103.

BASES

ACTIONS

E.1 (continued)

According to Regulatory Guide 1.93 (Ref. 6), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours. This Completion Time assumes complete loss of onsite (DG) AC capability to power the minimum loads needed to respond to analyzed events. In the event Division 3 DG in conjunction with Division 1 or 2 DG is inoperable, with Division 1 or 2 remaining, a significant spectrum of breaks would be capable of being responded to with onsite power. Even the worst case event would be mitigated to some extent—an extent greater than a typical two division design in which this condition represents complete loss of onsite power function. Given the remaining function, a 24 hour Completion Time is appropriate. At the end of this 24 hour period, Division 3 systems could be declared inoperable (see Applicability Note) and this Condition could be exited with only one required DG remaining inoperable. However, with a Division 1 or 2 DG remaining inoperable and the HPCS declared inoperable, a redundant required feature failure exists, according to Required Action B.2.

F.1 ~~and F.2~~

overall plant risk is minimized.

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 MODE 3 within 12 hours ~~and to MODE 4 within 36 hours~~. The allowed Completion Time~~s~~ ~~are~~ is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Insert 1

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.

(continued)

BASES (continued)

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. 8). 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 (Refs. 3 and 15), Regulatory Guide 1.108 (Ref. 9), and Regulatory Guide 1.137 (Ref. 10).

Where the SRs discussed herein specify voltage and frequency tolerances, the minimum and maximum steady state output voltages of 4084 V and 4580 V respectively, are equal to - 2% and + 10% of the nominal 4160 V output voltage. The specified minimum and maximum frequencies of the DG is 58.8 Hz and 61.2 Hz, respectively, are equal to ± 2% of the 60 Hz nominal frequency. The specified steady state voltage and frequency ranges are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3). However, the minimum voltage was increased to ensure adequate voltage to operate all safety-related loads during a DBA (Ref. 14).

In general, surveillances performed for each of the required DGs are similar, with one notable difference due to the fact that the Division 3 DG utilizes a mechanical governor, while the Division 1 and 2 DGs utilize an electronic governor. As such, the Division 1 and 2 DGs are capable of operating in both an isochronous mode as well as a "droop" mode for when the DGs are paralleled to the offsite source during testing. The Division 3 DG, on the other hand, is capable of operating only in the droop mode (through a droop setting of zero can be utilized). This difference may affect the Division 3 DGs capability to achieve rated frequency following automatic switchover from the test mode to ready-to-load operation upon receipt of a LOCA initiation signal (as verified per SR 3.8.1.17).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

The normal 31 day Frequency for SR 3.8.1.2 (see Table 3.8.1-1, "Diesel Generator Test Schedule") is consistent with the industry guidelines for assessment of diesel generator performance (Ref. ~~12~~). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

With regard to required voltage and frequency values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. ~~16, 17, 18, 21, 22~~). 17, 18, 19, 22, 23

SR 3.8.1.3

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting greater than or equal to the equivalent of the maximum expected accident loads. However, consistent with the recommendations of Regulatory Guide 1.9, Revision 3 (Ref. ~~15~~), this surveillance is performed with a DG load equal to or greater than 90 percent of its continuous rating. 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 normal 31 day Frequency for this Surveillance (see Table 3.8.1-1) is consistent with the industry guidelines for assessment of diesel generator performance (Ref. ~~12~~).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, 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.

Note 3 indicates that this Surveillance shall 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.

With regard to DG loading values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~19~~). 20

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the low level alarm setpoint. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at maximum expected post LOCA loads.

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

With regard to fuel oil level values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~20~~). 21

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is an 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, 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 Frequency is established by Regulatory Guide 1.137 (Ref. ~~10~~ 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.

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 the 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 design of fuel transfer systems is such that pumps operate automatically in order to maintain an adequate volume of fuel oil in the day tanks during or following DG testing. Therefore, a 31 day Frequency is specified to correspond to the maximum interval for DG testing.

SR 3.8.1.7

See SR 3.8.1.2.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

The referenced load for DG 1A is the low pressure core spray pump; for DG 1B, the residual heat removal (RHR) pump; and for DG 1C the HPCS pump. The Shutdown Service Water (SX) pump values are not used as the largest load since the SX supplies cooling to the associated DG. If this load were to trip, it would result in the loss of the DG. The use of larger loads for reference purposes is acceptable. This Surveillance may be accomplished by:

1) Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest load while paralleled to offsite power, or while supplying the bus, or

2) Tripping its associated single largest load with the DG supplying the bus.

14 As required by IEEE-308 (Ref. ~~13~~), 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.

The 24 month Frequency is consistent with the refuel cycle recommendations of Regulatory Guide 1.9 (Ref. ~~15~~). 16

This SR has been modified by two Notes. The intent of Note 1 is to indicate that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9 (continued)

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related (and non-safety related) distribution systems are aligned to the other offsite source (or unit auxiliary transformers). This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.

With regard to diesel speed values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~23~~). 24

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load, i.e., maximum expected accident load, without overspeed tripping or exceeding the predetermined voltage limits. However, consistent with the recommendations of Regulatory Guide 1.9, Revision 3 (Ref. ~~15~~), this surveillance is performed with a DG load equal to or greater than 90 percent of its continuous rating. 16

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

While the DG is not expected to experience this transient during an event and continue to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

The 24 month Frequency is consistent with the refuel cycle recommendation of Regulatory Guide 1.9 (Ref. ~~13~~) and is intended to be consistent with expected fuel cycle lengths. 16

This SR has been modified by a Note. The intent of the Note is to indicate that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related (and non-safety related) distribution systems are aligned to the other offsite source (or unit auxiliary transformers). This minimizes the possibility of common cause failure resulting from offsite/grid voltage perturbations.

This Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite of grid perturbations.

With regard to DG load and voltage values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~23~~). 24

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11

As required by Regulatory Guide 1.108 (Ref. ~~9~~ 10), paragraph 2.a.(1), 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 Division 1 and 2 nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

With regard to required voltage and frequency values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. ~~16, 17, 18~~ 17, 18, 19).

The DG auto-start time of 12 seconds is derived from requirements of the accident analysis to respond 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.

With regard to DG auto-start time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Ref. ~~21~~ 22).

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 DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, systems are not capable of being operated at

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

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.

The Frequency of 24 months is consistent with the refuel cycle recommendations of Regulatory Guide 1.9 (Ref. ~~13~~ 16), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. This allowance is not intended to impose a maximum limit on engine temperatures. 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 plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (12 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

With regard to DG start time, required voltage and frequency values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. ~~16~~, ~~17, 18, 21, 22~~).
17, 18, 19, 22, 23

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. Therefore, the Frequency was concluded to be 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. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. This allowance is not intended to impose a maximum limit on engine temperatures. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.14

Regulatory Guide 1.9, Revision 3 (Ref. ~~15~~ 16) requires demonstration once per 24 months that the DGs can start and run continuously at or near full-load capability for an interval of not less than 24 hours. The DGs are to be loaded equal to or greater than 105 percent of the continuous rating for at least 2 hours and equal to or greater than 90 percent of the continuous rating for the remaining hours of the test (i.e., 22 hours) (Ref. ~~15~~ 16). The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

The 24 month Frequency is consistent with the refuel cycle recommendations of Regulatory Guide 1.9, Revision 3 (Ref. ~~15~~ 16); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by two Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. The intent of Note 2 is to indicate that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related (and non-safety related) distribution systems are aligned to the other offsite source (or unit auxiliary transformers). This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.

With regard to DG loading capability values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~19~~ 20).

SR 3.8.1.15

This Surveillance is consistent with the recommendations of Regulatory Guide 1.108 (Ref. ~~8~~ 10), paragraph 2.a.(5), and demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 12 seconds. The 12 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA.

With regard to DG loading values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~19~~ 20).

With regard to DG start time, frequency and voltage values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. ~~16, 17, 18, 21, 22~~ 17, 18, 19, 22, 23).

The 24 month Frequency is consistent with the refuel cycle recommendations of Regulatory Guide 1.9, Revision 3 (Ref. ~~18~~ 16).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

This SR has been modified by two 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 (i.e., equal to or greater than 90 percent of the continuous rating) prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. 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 to minimize wear and tear on the diesel during testing.

SR 3.8.1.16

As required by Regulatory Guide 1.108 (Ref. ~~9~~ 10), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and load transfer from the DG to each offsite power source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the undervoltage 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 output breaker is open and can receive an auto-close signal on bus undervoltage, and the load sequence timers are reset.

Portions of the synchronization circuit are associated with the DG and portions with the offsite circuit. If a failure in the synchronization requirement of the Surveillance occurs, depending on the specific affected portion of the synchronization circuit, either the DG or the associated offsite circuit is declared inoperable.

The Frequency of 24 months is consistent with the refuel cycle recommendations of Regulatory Guide 1.9 (Ref. ~~15~~ 16), and takes into consideration plant conditions required to perform the Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.17

Demonstration of the test mode override is consistent with the recommendations of Regulatory Guide 1.108 (Ref. ~~9~~), paragraph 2.a.(8)and ensures that the DG availability under accident conditions is not compromised as the result of testing. Except as clarified below for the Division 3 DG, 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 with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. ~~13~~), paragraph 6.2.6(2), as further amplified by IEEE 387, sections 5.6.1 and 5.6.2. (Clarification regarding conformance of the Division 3 DG design to these standards is provided in the USAR, Chapter 8 (Reference 2).)

Automatic switchover from the test mode to ready-to-load operation for the division 3 DG is also demonstrated, as described above, by ensuring that DG control logic automatically resets in response to a LOCA signal during the test mode and confirming that ready-to-load operation is attained (as evidenced by the DG running with the output breaker open). However, with the DG governor initially operating in a "droop" condition during the test mode, operator action may be required to reset the governor for

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

ready-to-load operation in order to complete the surveillance for the Division 3 DG. Resetting the governor ensures that the DG will supply the Division 3 bus at the required frequency in the event of a LOCA and a loss of offsite power while the DG is in a droop condition during the test mode.

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 requirement 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 testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 24 month Frequency is consistent with the refuel cycle recommendations of Regulatory Guide 1.9 (Ref. ~~15~~); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths. 16

This SR has been modified by a Note. The intent of this note is to indicate that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related (and non-safety related) distribution systems are aligned to the other offsite source (or unit auxiliary transformers). This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

Under accident conditions with a loss of offsite power, loads are sequentially connected to the bus by the load sequencing logic (except for Division 3 which has no load sequence timers). The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated and is consistent with the recommendations of Regulatory Guide 1.108 (Ref. ~~8~~ 10), paragraph 2.a.(2). Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 24 months is consistent with the refuel cycle recommendations of Regulatory Guide 1.9 (Ref. ~~15~~ 16); 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. The reason for the Note is that performing the Surveillance during these MODES may perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

With regard to sequence time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~24~~ 25).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

With regard to DG start time, required voltage and frequency values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. ~~16, 17, 18, 21~~). 17, 18, 19, 22

SR 3.8.1.20

This Surveillance is performed with the plant shut down and 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.

10 The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. ~~8~~).

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. This allowance is not intended to impose a maximum limit on engine temperatures.

With regard to required voltage and frequency values obtained pursuant to this SR, as read from plant indication

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. ~~16, 17, 18, 21, 22~~ 17, 18, 19, 22, 23).

Diesel Generator Test Schedule

The DG test schedule (Table 3.8.1-1) implements the industry guidelines for assessment of diesel generator performance (Ref. ~~12~~ 13). The purpose of this test schedule is to provide timely test data to establish a confidence level associated with the goal to maintain DG reliability at > 0.95 per test.

According to the industry guidelines (Ref. ~~12~~ 13), each DG unit should be tested at least once every 31 days. Whenever a DG has experienced 4 or more valid failures in the last 25 valid tests, the maximum time between tests is reduced to 7 days. Four failures in 25 valid tests is a failure rate of 0.16, or the threshold of acceptable DG performance, and hence may be an early indication of the degradation of DG reliability. When considered in the light of a long history of tests, however, 4 failures in the last 25 valid tests may only be a statistically probable distribution of random events. Increasing the test Frequency allows a more timely accumulation of additional test data upon which to base judgment of the reliability of the DG. The increased test Frequency must be maintained until seven consecutive failure free tests have been performed.

The Frequency for accelerated testing is 7 days, but no less than 24 hours. Tests conducted at intervals of less than 24 hours may be credited for compliance with Required Actions. However, for the purpose of re-establishing the normal 31-day Frequency, a successful test at an interval of less than 24 hours should be considered an invalid test and not count towards the seven consecutive failure free starts, and the consecutive test count is not reset.

A test interval in excess of 7 days (or 31 days, as appropriate) constitutes a failure to meet SRs and results in the associated DG being declared inoperable. It does not, however, constitute a valid test or failure of the DG, and any consecutive test count is not reset.

(continued)

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. USAR, Chapter 8.
3. Regulatory Guide 1.9, Revision 2.
4. USAR, Chapter 6.
5. USAR, Chapter 15.
6. Regulatory Guide 1.93.
7. Generic Letter 84-15, July 2, 1984.

Insert 2

9. ~~8.~~ 10 CFR 50, Appendix A, GDC 18.
10. ~~9.~~ Regulatory Guide 1.108.
11. ~~10.~~ Regulatory Guide 1.137.
12. ~~11.~~ ANSI C84.1, 1982.
13. ~~12.~~ NUMARC 87-00, Revision 1, August 1991.
14. ~~13.~~ IEEE Standard 308.
15. ~~14.~~ IP Calculation 19-AN-19.
16. ~~15.~~ Regulatory Guide 1.9, Revision 3.
17. ~~16.~~ Calculation IP-C-0050.
18. ~~17.~~ Calculation IP-C-0051.
19. ~~18.~~ Calculation IP-C-0054.
20. ~~19.~~ Calculation IP-0-0114.
21. ~~20.~~ Calculation IP-C-0111.
22. ~~21.~~ Calculation IP-0-0106.
23. ~~22.~~ Calculation IP-0-0143.
24. ~~23.~~ Calculation IP-0-0110.
25. ~~24.~~ Calculation IP-0-0116.

BASES

ACTIONS (continued)

Insert 1

~~D.1~~ E.1

With one or more Division 3 or 4 DC electrical power subsystems inoperable, the HPCS System may be incapable of performing its intended functions and must be immediately declared inoperable. This declaration also requires entry into applicable Conditions and Required Actions of LCO 3.5.1, "ECCS—Operating."

~~E.1 and E.2~~ F.1 and F.2

If the inoperable DC electrical power subsystem 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 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. The Completion Time to bring the unit to MODE 4 is consistent with the time required in Regulatory Guide 1.93 (Ref. 7).

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to continually charge the battery. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the minimum float voltage established by the battery manufacturer (2.20 Vpc or 127.6 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). The 7 day Frequency is consistent with manufacturer's recommendations and IEEE-450 (Ref. ~~8~~ 9).

With regard to battery terminal voltage values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~12~~ 13).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.2

This SR verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32 (Ref. ~~9~~), the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied. This SR provides two options. One option requires that each battery charger be capable of supplying 300 amps for Divisions 1 and 2 (100 amps for Divisions 3 and 4) at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours. 10

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest coincident demands of the various continuous steady state loads (irrespective or the status of the plant during which these demands occur). This level of loading may not normally be available following the battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is $\leq$ 2 amps.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

With regard to minimum required amperes and duration values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~12~~). 13

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.3

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length are established with a dummy load that corresponds to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of 24 months is an exception to the recommendations of Regulatory Guide 1.32 (Ref. ~~9~~ 10) and Regulatory Guide 1.129 (Ref. ~~10~~ 11), which state that the battery service test should be performed during refueling operations or at some other outage, with intervals between tests not to exceed 18 months.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test SR 3.8.6.6 in lieu of SR 3.8.4.3. This substitution is acceptable because SR 3.8.6.6 represents an equivalent test of battery capability as SR 3.8.4.3. The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

With regard to battery capacity values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~11~~ 12).

(continued)

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE Standard 308, 1978.
4. USAR, Section 8.3.2.
5. USAR, Chapter 6.
6. USAR, Chapter 15.
7. Regulatory Guide 1.93, December 1974.

Insert 2

9. ~~8~~. IEEE Standard 450, 1995.
10. ~~9~~. Regulatory Guide 1.32, February 1977.
11. ~~10~~. Regulatory Guide 1.129, December 1974.
12. ~~11~~. Calculation IP-0-0123.

BASES

ACTIONS

A.1 (continued)

2. Evaluate concurrent maintenance or inoperable status of any of the remaining three instrument bus inverters for the unit.

3. Evaluate simultaneous EDG maintenance.

Insert 1

~~B.1~~ C.1

With one or more Division 3 or 4 inverters inoperable, the associated Division 3 ECCS subsystem may be incapable of performing intended function and must be immediately declared inoperable. This also requires entry into applicable Conditions and Required Actions for LCO 3.5.1, "ECCS—Operating."

D.1.1, D.1.2, and D.2

~~C.1.1, C.1.2, and C.2~~

With one RPS solenoid bus inverter inoperable it may be incapable of providing voltage and frequency regulated power

(continued)

BASES

ACTIONS

~~C.1.1, C.1.2, and C.2~~ (continued)

D.1.1, D.1.2, and D.2

sufficient to protect the loads connected to the bus. In this condition, the source of power must be transferred or removed from service. If the RPS bus power is transferred to its alternate source, an additional ACTION is required to periodically monitor the frequency on the bus. This frequency is designed to be limited by the in-line RPS electric power monitoring assembly (required by LCO 3.3.8.2, "RPS Electric Power Monitoring"), however, in the event of a single failure, frequency protection would not be available. Should frequency be discovered < 57 Hz, additional ACTIONS are required in LCO 3.3.8.2 due to the inoperable RPS electric power monitoring assembly.

The 1 hour Completion Time is sufficient for plant personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration, transfer or removal of the RPS bus power supply from service.

E.1
~~D.1~~

With both RPS solenoid bus inverters inoperable both RPS buses may be incapable of providing voltage and frequency regulated power sufficient to protect the loads connected to the buses. In this condition, the source of power must be transferred or removed from service, however, only one RPS bus is allowed to be powered from an alternate source at any one time. Therefore, at least one RPS solenoid bus must be de-energized. The remaining affected bus will be de-energized or powered from its alternate source in accordance with Condition ~~C~~ D.

The 1 hour Completion Time is sufficient for plant personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration or removal of the RPS bus power supply from service.

F.1 and F.2
~~E.1 and E.2~~

If the inoperable devices or components 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

(continued)

BASES

ACTIONS

F.1 and F.2

~~E.1 and E.2~~ (continued)

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.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and uninterruptible AC buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the uninterruptible AC buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

With regard to voltage and frequency values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~4~~). 5

REFERENCES

1. USAR, Chapter 8.
2. USAR, Chapter 6.
3. USAR, Chapter 15.

Insert 2

5. ~~4.~~ Calculation IP-0-0131.

BASES

ACTIONS

C.1 (continued)

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without DC power while not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC division could again become inoperable, and DC distribution could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

D.1 ~~and D.2~~

If the inoperable electrical power distribution system cannot be restored to OPERABLE status within the associated Completion Times, the plant must be bought 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~~

overall plant risk is minimized.

is

Insert 1

(continued)

BASES

ACTIONS

D.1 ~~and D.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.

E.1

With one or more Division 3 or 4 electrical power distribution system(s) inoperable, the Division 3 or 4 powered systems are not capable of performing their intended functions. Immediately declaring the high pressure core spray inoperable allows the ACTIONS of LCO 3.5.1, "ECCS-Operating," to apply appropriate limitations on continued reactor operation.

F.1

Condition F corresponds to a level of degradation in the electrical distribution system that causes a required safety function to be lost. When more than one Condition is entered, and this results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

Meeting this Surveillance verifies that the required AC, DC, and uninterruptible AC bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1 (continued)

these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and uninterruptible AC bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

With regard to voltage values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. ~~5~~ 6).

REFERENCES

1. USAR, Chapter 6.

2. USAR, Chapter 15.

3. Regulatory Guide 1.93, December 1974.

Insert 2

5. ~~4~~. USAR, Section 8.3.

6. ~~5~~. Calculation IP-0-0132.

Clinton Power Station TSTF-423 LAR
Technical Specification Bases Page Inserts

LCO 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.5.1 ECCS-Operating

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 13) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

13. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.6.1.1 Primary Containment

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 5), because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

5. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.6.1.6 Low-Low Set (LLS) Valves

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

C.1 and C.2

If two or more LLS valves are inoperable, there could be excessive short duration S/RV cycling during an overpressure event. 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 and 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.

Insert 3

2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.6.1.7 Residual Heat Removal (RHR) Containment Spray System

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.6.1.9 Feedwater Leakage Control System (FWLCS)

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status

will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

If two RHR suppression pool cooling subsystems are inoperable, 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.

Insert 3

2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.6.4.1 Secondary Containment

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 3), because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

3. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.6.4.3 Standby Gas Treatment (SGT) System

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 9) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

Therefore, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 9) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Insert 3

9. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.6.5.6 Drywell Post-LOCA Vacuum Relief System

Insert 1

E.1

If one drywell post-LOCA vacuum relief subsystem is inoperable for reasons other than Condition A or two or more drywell post-LOCA vacuum relief subsystems are inoperable for reasons other than Condition A, and not restored within the provided Completion Time, the plant must be brought to a condition in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Insert 2

2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.7.1 Division 1 and 2 SX Subsystems and UHS

Insert 1

C.1

If the Required Action and associated Completion Time of Condition B is not met, the plant must be brought to a condition in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 8) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Insert 2

8. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.7.3 Control Room Ventilation System

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 5) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

Therefore, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 5) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions is an orderly manner and without challenging plant systems.

Insert 3

5. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.7.4 Control Room Air Conditioning (AC) System

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 3) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

3. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.7.5 Main Condenser Offgas

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 4) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

4. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.8.1 AC Sources – Operating

Insert 1

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 8) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Insert 2

8. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.8.4 DC Sources – Operating

Insert 1

D.1

If a Division 1 or 2 DC electrical power subsystem is inoperable and not restored within the provided Completion Time, the plant must be brought to a condition in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 8) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Insert 2

8. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.8.7 Inverters – Operating

Insert 1

B.1

If a Division 1 or 2 inverter is inoperable and not restored within the provided Completion Time, the plant must be brought to a condition in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 4) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Insert 2

4. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

LCO 3.8.9 Distribution Systems – Operating

Insert 1

C.1

If one or both Division 1 and 2 AC or DC electrical power distribution subsystems are inoperable and not restored within the provided Completion Time, the plant must be brought to a condition in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 4) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Insert 2

4. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

ATTACHMENT 4
List of Regulatory Commitments

The following table identifies those actions committed to by AmerGen Energy Company, LLC (AmerGen) in this document. Any other statements in the submittal are provided for information purposes and are not considered to be regulatory commitments.

COMMITMENT	COMMITTED DATE	COMMITMENT TYPE	
		ONE-TIME ACTION (Yes/No)	PROGRAMMATIC (Yes/No)
AmerGen will follow the guidance established in Section 11 of NUMARC 93-01, "Industry Guidance for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Nuclear Management and Resource Council, Revision 3, July 2000.	Ongoing	No	Yes
AmerGen will follow the guidance established in TSTF-IG-05-02, "Implementation Guidance for TSTF-423, Revision 0, 'Technical Specifications End States, NEDC-32988-A,'" Revision 1, March 2007.	Implement with amendment	No	Yes