IMPROVED TECHNICAL SPECIFICATION BASES

Electronic transcription by:
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TECHNICAL SPECIFICATION BASES
LIST OF EFFECTIVE SECTIONS

BASES SECTION	REV	NUMBER OF PAGES	EFFECTIVE DATE
TOC	4	4	06/27/2008
B 2.0 SAFETY LIMITS			
B 2.1.1	1	4	06/03/2005
B 2.1.2	1	4	06/03/2005
B 3.0 LCO AND SR APPLICABILITY			
B 3.0	**4**	**18**	**08/22/2019**
B 3.1 REACTIVITY CONTROL			
B 3.1.1	1	6	06/03/2005
B 3.1.2	0	7	03/19/2001
B 3.1.3	3	7	02/20/2018
B 3.1.4	0	13	03/19/2001
B 3.1.5	0	5	03/19/2001
B 3.1.6	0	6	03/19/2001
B 3.1.7	0	8	03/19/2001
B 3.1.8	0	7	03/19/2001
B 3.2 POWER DISTRIBUTION LIMITS			
B 3.2.1	1	7	01/15/2014
B 3.2.2	2	7	01/15/2014
B 3.2.3	0	9	03/19/2001
B 3.2.4	0	7	03/19/2001
B 3.3 INSTRUMENTATION			
B 3.3.1	5	57	02/20/2018
B 3.3.2	7	46	02/20/2018
B 3.3.3	12	18	07/31/2018
B 3.3.4	3	6	07/31/2018
B 3.3.5	4	6	02/20/2018
B 3.3.6	1	8	04/11/2005
B 3.3.7	2	6	07/31/2014
B 3.3.8	3	4	08/21/2014
B 3.4 REACTOR COOLANT SYSTEM			
B 3.4.1	4	6	02/20/2018
B 3.4.2	0	3	03/19/2001
B 3.4.3	7	7	02/20/2018
B 3.4.4	1	4	04/11/2007
B 3.4.5	1	6	04/11/2007
B 3.4.6	2	6	04/11/2007
B 3.4.7	1	7	04/11/2007
B 3.4.8	0	4	03/19/2001
B 3.4.9	5	5	05/17/2012
B 3.4.10	2	5	05/17/2012
B 3.4.11	2	7	05/17/2012
B 3.4.12	9	15	02/20/2018
B 3.4.13	5	7	07/31/2014
B 3.4.14	2	10	05/17/2012
B 3.4.15	5	7	07/31/2014
B 3.4.16	3	5	07/31/2008
B 3.4.17	1	8	02/20/2018
B 3.5 ECCS			
B 3.5.1	1	10	10/27/2004
B 3.5.2	6	12	05/17/2012
B 3.5.3	3	4	07/31/2014

BASES SECTION	REV	NUMBER OF PAGES	EFFECTIVE DATE
B 3.5.4	5	9	08/21/2014
B 3.6 CONTAINMENT			
B 3.6.1	0	5	03/19/2001
B 3.6.2	2	9	08/21/2014
B 3.6.3	1	17	08/21/2014
B 3.6.4	1	3	08/21/2014
B 3.6.5	3	5	02/10/2010
B 3.6.6	6	14	02/20/2018
B 3.6.7	3	4	07/31/2014
B 3.6.8	1	1	08/10/2005
B 3.6.9	1	8	06/03/2005
B 3.6.10	2	12	09/16//2005
B 3.7 PLANT SYSTEMS			
B 3.7.1	3	6	05/17/2012
B 3.7.2	3	10	05/17/2012
B 3.7.3	2	7	05/17/2012
B 3.7.4	2	4	05/02/2013
B 3.7.5	6	10	02/22/2013
B 3.7.6	3	4	08/22/2008
B 3.7.7	1	4	12/17/2004
B 3.7.8	4	7	02/20/2018
B 3.7.9	4	9	10/10/2018
B 3.7.10	2	3	07/31/2014
B 3.7.11	7	10	07/31/2014
B 3.7.12	3	4	07/31/2014
B 3.7.13	5	7	12/10/2014
B 3.7.14	1	3	04/11/2005
B 3.7.15	1	4	07/30/2012
B 3.7.16	0	6	03/19/2001
B 3.7.17	1	4	06/03/2005
B 3.8 ELECTRICAL POWER			
B 3.8.1	9	31	03/08/2019
B 3.8.2	2	7	03/08/2019
B 3.8.3	3	13	02/04/2011
B 3.8.4	3	11	07/31/2014
B 3.8.5	0	4	03/19/2001
B 3.8.6	0	8	03/19/2001
B 3.8.7	2	7	07/31/2014
B 3.8.8	1	4	06/20/2003
B 3.8.9	3	14	07/31/2014
B 3.8.10	0	4	03/19/2001
B 3.9 REFUELING OPERATIONS			
B 3.9.1	1	4	07/06/2006
B 3.9.2	0	4	03/19/2001
B 3.9.3	2	7	06/03/2005
B 3.9.4	0	4	03/19/2001
B 3.9.5	0	4	03/19/2001
B 3.9.6	2	3	04/11/2005

APPENDIX C BASES SECTION	REV	NUMBER OF PAGES	ISSUE DATE
TOC	0	1	07/30/2012
B 3.0 LCO AND SR APPLICABILITY			
B 3.0	0	7	07/30/2012
B 3.1 INTER-UNIT FUEL TRANSFER			
B 3.1.1	0	4	07/30/2012
B 3.1.2	1	6	02/20/2018
B 3.1.3	0	2	07/30/2012
B 3.1.4	0	3	07/30/2012
B 3.1.5	0	4	07/30/2012

REVISION HISTORY FOR IP3 BASES

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
ALL	0	03/19/01	Initial issue of Bases derived from NUREG-1431, in conjunction with Technical Specification Amendment 205 for conversion of 'Current Technical Specifications' to 'Improved Technical Specifications'.
BASES UPDATE PACKAGE 01-031901			
B 3.4.13 B 3.4.15	1	03/19/01	Changes regarding containment sump flow monitor per NSE 01-3-018 LWD Rev 0. Change issued concurrent with Rev 0.
BASES UPDATE PACKAGE 02-051801			
Table of Contents	1	05/18/01	Title of Section B 3.7.3 revised per Tech Spec Amend 207
B 3.7.3	1	05/18/01	Implementation of Tech Spec Amend 207
BASES UPDATE PACKAGE 03-111901			
B 3.3.2	1	11/19/01	Correction to statement regarding applicability of Function 5, to be consistent with the Technical Specification.
B 3.3.3	1	11/19/01	Changes to reflect reclassification of certain SG narrow range level instruments as QA Category M per NSE 97-3-439, Rev 1.
B 3.4.13 B 3.4.15	2	11/19/01	Changes to reflect installation of a new control room alarm for 'VC Sump Pump Running'. Changes per NSE 01-3-018, Rev 1 and DCP 01-3-023 LWD.
B 3.7.11	1	11/19/01	Clarification of allowable flowrate for CRVS in 'incident mode with outside air makeup.'
BASES UPDATE PACKAGE 04-012202			
B 3.3.2	2	01/22/02	Clarify starting logic of 32 ABFP per EVL-01-3-078 MULTI, Rev 0.
B 3.8.1	1	01/22/02	Provide additional guidance for SR 3.8.1.1 and Condition Statements A.1 and B.1 per EVL-01-3-078 MULTI, Rev 0.
B 3.8.4	1	01/22/02	Revision of battery design description per plant modification and to reflect Tech Spec Amendment 209.
B 3.8.9	1	01/22/02	Provide additional information regarding MCC in Table B 3.8.9-1 per EVL-01-3-078 MULTI, Rev 0.
BASES UPDATE PACKAGE 05-093002			
B 3.0	1	09/30/02	Changes to reflect Tech Spec Amendment 212 regarding delay period for a missed surveillance. Changes adopt TSTF 358, Rev 6.
B 3.3.1	1	09/30/02	Changes regarding description of turbine runback feature per EVAL-99-3-063 NIS.
B 3.3.3	2	09/30/02	Changes to reflect Tech Spec Amendment 211 regarding CETs and other PAM instruments.

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
B 3.7.9	1	09/30/02	Changes regarding SWN -35-1 and -2 valves per EVAL-00-3-095 SWS, Rev 0.
BASES UPDATE PACKAGE 06-120402			
B 3.3.2 B 3.6.6 B 3.7.1 B 3.7.6	3 1 1 1	12/04/02	Changes to reflect Tech Spec Amendment 213 regarding 1.4% power uprate.
BASES UPDATE PACKAGE 07-031703			
B 3.3.8 B 3.7.13 B 3.9.3	1 1 1	03/17/2003	Changes to reflect Tech Spec Amendment 215 regarding implementation of Alternate Source Term analysis methodology to the Fuel Handling Accident.
BASES UPDATE PACKAGE 08-032803			
B 3.4.9	1	03/28/2003	Changes to reflect Tech Spec Amendment 216 regarding relaxation of pressurizer level limits in MODE 3.
BASES UPDATE PACKAGE 09-062003			
B 3.4.9	2	06/20/2003	Changes to reflect commitment for a dedicated operator per Tech Spec Amendment 216.
B 3.6.5	1	06/20/2003	Implements Corrective Action 11 from CR-IP3-2002-02095; 4 FCUs should be in operation to assure representative measurement of containment air temperature.
B 3.7.11	2	06/20/2003	Correction to Background description regarding system response to Firestat detector actuation per ACT 02-62887.
B 3.7.13	2	06/20/2003	Revision to Background description of FSB air tempering units to reflect design change per DCP 95-3-142.
B 3.8.7 B 3.8.8 B 3.8.9	1 1 2	06/20/2003 06/20/2003 06/20/2003	Changes to reflect replacement of Inverter 34 per DCP-01-022.
BASES UPDATE PACKAGE 10-102704			
B 3.1.3	1	10/27/2004	Clarification of the surveillance requirements for TS 3.1.3 per 50.59 screen.
B 3.3.5	1	10/27/2004	Clarify the requirements for performing a Trip Actuating Device Operational Test (TADOT) on the 480V degraded grid and undervoltage relays per 50.59 screen.
B 3.4.3 B 3.4.12	1 1	10/27/2004	Extension of the RCS pressure/temperature limits and corresponding OPS limits from 16.17 to 20 EFPY (TS Amendment 220).
B 3.5.1	1	10/27/2004	Changes to reflect Tech Spec Amendment 222 regarding extension of completion time for Accumulators.
BASES UPDATE PACKAGE 11-121004			
B 3.7.7	1	12/17/2004	Addition of valves CT-1300 and CT-1302 to Surveillance SR 3.7.7.2 to verify that all city water header supply

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
			isolation valves are open. Reflects Tech Spec Amendment 218.
BASES UPDATE PACKAGE 12-012405			
B 3.7.11	3	01/24/2005	Temporary allowance for use of KI/SCBA for unfiltered inleakage above limit.
BASES UPDATE PACKAGE 13-022505			
B 3.7.5	1	02/25/2005	Clarification on Surveillance Requirement 3.7.5.3 as it relates to plant condition/frequency of performance of Auxiliary Feedwater Pump full flow testing.
BASES UPDATE PACKAGE 14-030705			
B 3.9.6	1	03/07/2005	Changes to reflect that the decay time prior to fuel movement is a minimum of 84 hours per Tech Spec Amendment 215.
BASES UPDATE PACKAGE 15-041105			
B 3.3.2 B 3.3.6 B. 3.3.7 B 3.7.11 B 3.7.12 B 3.7.14 B 3.9.6	4 1 1 4 1 1 2	04/11/2005	Changes to reflect AST as per Tech Spec Amendment 224. NOTE: In addition to the AST changes to B. 3.7.11, the temporary allowance for use of KI/SCBA for unfiltered inleakage above limit is being removed. Tracer Gas testing is complete.
BASES UPDATE PACKAGE 16-060305			
B 2.1.1 B 2.1.2 B 3.1.1 B 3.2.2 B 3.3.1 B 3.3.8 B 3.4.1 B 3.4.3 B 3.4.6 B 3.4.9 B 3.4.13 B 3.4.16 B 3.5.2 B 3.6.2 B 3.6.6 B 3.6.7 B 3.6.9 B 3.6.10 B 3.7.1 B 3.7.2 B 3.7.5	1 1 1 1 2 2 1 2 1 3 3 1 1 1 2 1 1 1 2 1 2	06/03/2005	Changes to reflect SPU as per Tech Spec Amendment 225.

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
B 3.7.6 B 3.7.8 B 3.7.9 B 3.7.10 B 3.7.13 B 3.7.17 B 3.9.3	2 1 2 1 3 1 2		
BASES UPDATE PACKAGE 17-081005			
TOC B 3.0 B 3.3.3 B 3.3.4 B 3.4.11 B 3.4.12 B 3.4.15 B 3.4.16 B 3.5.3 B 3.6.8 B 3.7.4 B 3.7.5 B 3.7.11 B 3.8.1	2 2 3 1 1 2 3 2 1 1 1 3 5 2	08/10/2005	B 3.3.3, B 3.6.8 – Removal of Hydrogen Recombiners from the bases as per Technical Specification Amendment 228. B 3.3.3 is also affected by Amendment 226. B 3.7.11 - Add reference that if the primary coolant source of containment is in question, refer to ITS 5.5.2. All other bases changes for this revision are associated with Technical Specification Amendment 226 regarding increase flexibility in Mode Restraints.
BASES UPDATE PACKAGE 18-091605			
B 3.5.2 B 3.6.10	2 2	09/16/2005	Reflect implementation of ER-04-2-029 as part of Stretch Power Uprate (SPU) – HHSI Modification. Update LCO and Condition B to clarify required actions consistent with FSAR.
BASES UPDATE PACKAGE 19-110405			
B 3.8.1	3	11/04/2005	Include operability criteria for 138 kV and 13.8 kV offsite circuits.
BASES UPDATE PACKAGE 20-070606			

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
B 3.9.1	1	07/06/2006	Clarification on effective method for ensuring shutdown margin.
BASES UPDATE PACKAGE 21-11072006			
B 3.0	3	11/07/2006	Reflect allowing a delay time for entering a supported system TS when the inoperability is due solely to an inoperable snubber, if risk is assessed and managed. Limiting Condition of Operation 3.0.8 is added to provide this allowance and define the requirements and limitations of its use. (Amendment 229)
BASES UPDATE PACKAGE 22-04112007			
TOC B 3.4.4 B 3.4.5 B 3.4.6 B 3.4.7 B 3.4.13 B 3.4.17	3 1 1 2 1 4 0	04/11/2007	Implement TS Amendment 233 related to steam generator tube integrity.
BASES UPDATE PACKAGE 23-05162007			
B 3.7.2	2	05/16/2007	Removal of extraneous information regarding testing frequency.
BASES UPDATE PACKAGE 24-10052007			
B 3.3.1 B 3.8.2	3 1	10/05/2007	B 3.3.1 – The TS and bases currently allow a normal shutdown without the SR testing by reducing power below the modes of applicability for SR 3.3.1.8. Clarify that testing is not required if such testing was done within the prior 92 days, even if a mode of applicability was still met. B 3.8.2 – Clarify LCO with regard to the required power sources for modes 5 and 6.
BASES UPDATE PACKAGE 25-11022007			
B 3.4.3 B 3.4.10 B 3.4.12	3 1 3	11/2/2007	Revise LTOP arming temperature and EFPY expiration date for RCS P/T curves to reflect implementation of License Amendment 235.
BASES UPDATE PACKAGE 26-06272008			
TOC B 3.6.6 B 3.6.7	4 3 2	6/27/2008	Revise sections to reflect Amendment 236 changing sodium hydroxide to sodium tetraborate
BASES UPDATE PACKAGE 27-07012008			
B 3.4.16	3	07/31/2008	Implement the Bases pages of TSTF 490 for dose equivalent iodine (Amendment 237)

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
BASES UPDATE PACKAGE 28-08222008			
B 3.3.3 B 3.7.6 B 3.4.15	4 3 4	08/22/2008	Revise sections to reflect SSFS Engineering Standard Changes to incorporate EN fleet level QA Safety Classifications. Clarify the method that the instrument performs containment sump flow monitoring and provide an acceptable alternative for the VC Sump Pump Running Control Room alarm.
BASES UPDATE PACKAGE 29-09162008			
B 3.8.3	1	09/16/2008	Reflect installation of Unit 2 Appendix R Diesel and removal of GTs.
BASES UPDATE PACKAGE 30-01202009			
B 3.7.11	6	01/20/2009	Implement the Bases pages of TSTF 488 for Control Room Envelope Habitability (Amendment 239)
BASES UPDATE PACKAGE 31-03182009			
B 3.8.1	4	3/18/2009	Correct typographical symbol error.
BASES UPDATE PACKAGE 32-07282009			
B 3.3.3 B 3.5.2 B 3.7.5	5 3 4	7/28/2009	Reflect rewiring of Train B CET K03. Reflect TS Amendment 257 (Passive Failure Analysis). Clarify SR 3.7.5.3 and 3.7.5.4 with respect to tests that deliver flow.
BASES UPDATE PACKAGE 33-08212009			
B 3.3.5 B 3.5.2	2 4	08/21/2009	Reflect TS Amendment 231 (TADOT). Addition of valves SI-2165, 2166, 2168, 2170, and 2172 and deletion of valves SI-856A and 856G of the ECCS valves to the surveillance (Amendment 230).

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
BASES UPDATE PACKAGE 34-10162009			
B 3.4.12 B 3.6.5	4 2	10/16/2009	B 3.4.12 – Reflect that the test does not require reduction to the LTOP setpoint to be approved. B 3.6.5 – Clarify that the initial containment temperature assumed in the LOCA analysis of record for peak cladding temperature (PCT) and impact on LOCA due to reduction in initial containment temperature from 90^{o}F to 80^{o}F.
BASES UPDATE PACKAGE 35-02052010			
B 3.6.5 B 3.8.1	3 5	02/10/2010	B 3.6.5 – Clarify that environmental qualification (EQ) temperature inside containment is based on LOCA, and to be consistent with EQ files and IP2 UFSAR. B 3.8.1 – Correct inaccuracies in SR 3.8.1.2 and 3.8.1.3 (CR-IP2-2009-04257).
BASES UPDATE PACKAGE 36-07142010			
B 3.5.2 B 3.5.3 B 3.5.4 B 3.7.8	5 2 1 2	07/14/2010	B 3.5.2, B 3.5.3 & B 3.7.8 – Clarifications and/or changes to the descriptions of Auxiliary Component Cooling Pumps operation and design functions (EC 19489). B 3.5.4 – Revise bases to reflect TS Amendment 241 which deleted “indicating” from “level indicating” from RWST SR 3.5.4.5.
BASES UPDATE PACKAGE 37-10042010			
B 3.8.3	2	10/04/2010	Clarify that to meet LCO air start motor must have 250 psig rather than 4 starts.
BASES UPDATE PACKAGE 38 - 02042011			
B 3.8.1 B 3.8.3 B 3.8.4	6 3 2	02/04/2011	Revise SR 3.8.1.10 non conservative test criteria and incorporate TSTF-283 and 276, in part. Add clarification regarding the starting air receiver pressures to clarify they are analytical limits. Clarify SR 3.8.4.2 to reflect TSTF-283.

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
BASES UPDATE PACKAGE 39 - 10132011			
B 3.3.3	5	10/13/2011	Revised the number of CET trains qualified per EC.
B3.5.4	2	10/13/2011	Reflects Amend 244 requirement for locks on heating steam.
B3.7.12	2	10/13/2011	Clarifies the CCR HVAC testing basis.
BASES UPDATE PACKAGE 40 – 05172012			
B 3.3.3	7	05/17/2012	Replace the existing plant process computer known as the Critical Function Monitoring System (CFMS), with a new, updated Plant Integrated Computer System, (PICS).
B 3.4.9	4		Retire Heater Bank 8.9.31 of Pressurizer Backup Heater Group 32
B 3.4.10	2		Revise the Bases to reflect Amendment 245 For ASME
B 3.4.11	2		Revise the Bases to reflect Amendment 245 For ASME
B 3.4.12	5		Insert additional methods of ensuring HHSI pumps are incapable of injecting into the core
B 3.4.14	1		Revise the Bases to reflect Amendment 245 For ASME
B 3.5.2	6		Revise the Bases to reflect Amendment 245 For ASME
B 3.6.6	4		Revise the Bases to reflect Amendment 245 For ASME
B 3.7.1	3		Revise the Bases to reflect Amendment 245 For ASME
B 3.7.2	3		Revise the Bases to reflect Amendment 245 For ASME
B 3.7.3	2		Revise the Bases to reflect Amendment 245 For ASME
B 3.7.5	5		Revise the Bases to reflect Amendment 245 For ASME
BASES UPDATE PACKAGE 41 – 07302012			
B 3.7.15	1	07/30/2012	Inter-Unit Spent Fuel Transfer – Revised Appendix A Technical Specifications and associated bases to reflect Amendment 246.
Appendix C Technical Spec. Bases	0	07/30/2012	Inter-Unit Spent Fuel Transfer – Added Appendix C and associated bases to reflect Amendment 246.

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
BASES UPDATE PACKAGE 42 – 02222013			
B 3.5.4	3	2/22/2013	Bases change for allowing RWST purification on manual action for outages 2R21 and 2R22.
B 3.7.5	6	2/22/2013	Clarify Bases to show instrument air not credited post accident.
BASES UPDATE PACKAGE 43 – 05142013			
B 3.3.2	5	5/14/2013	Change "Function 8" to "Function 7" to match TS
B 3.3.3	8	5/14/2013	Bases change for CET rewiring.
B 3.4.9	5	5/14/2013	Revise PZR SR Valve 411^{o}F to 380^{o}F to reflect Amendment 220
B 3.4.12	6	5/14/2013	Revise PZR SR Valve 411^{o}F to 380^{o}F to reflect Amendment 220
B 3.7.4	2	5/14/2013	Clarify that four ADV are required and there is no single failure per Amend 251.
BASES UPDATE PACKAGE 44 – 01152014			
B 3.2.1	1	01/15/2014	Bases change to clarify that the FQ(Z) measurement uncertainty of 5% is based on 75% available thimbles.
B 3.2.2	2	01/15/2014	Bases change to clarify that the $F^N_{\Delta H}$ measurement uncertainty of 4% is based on 75% available thimbles.
BASES UPDATE PACKAGE 45 – 07312014			
B 3.3.1	4	7/31/2014	Delete Ref 6 and replace with Refs 10, 11 and 12
B 3.3.2	6	7/31/2014	Change End State from Mode 5 to Mode 4, change NaOH to NaTB, delete Ref 6 and replace with Refs 10, 11 & 12
B 3.3.3	9	7/31/2014	Change 'B-series' instruments to indication loops
B 3.3.5	3	7/31/2014	Delete Ref. 3 and replace with Refs 4, 5 and 6
B 3.3.7	2	7/31/2014	Change End State from Mode 5 to Mode 4

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
B 3.4.13	5	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.4.14	2	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.4.15	5	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.5.3	3	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.5.4	4	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.6.6	5	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.6.7	3	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.7.8	3	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.7.9	3	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.7.10	2	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.7.11	7	7/31/2014	Change End State from Mode 5 to Mode 4, and change reference from ENN-DC-197 to IP-RPT-08-00001
B 3.7.12	3	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.8.1	7	7/31/2014	Change End State from Mode 5 to Mode 4, and change Reference 10
B 3.8.4	3	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.8.7	2	7/31/2014	Change End State from Mode 5 to Mode 4
B 3.8.9	3	7/31/2014	Change End State from Mode 5 to Mode 4
BASES UPDATE PACKAGE 46 – 08212014			
B 3.3.8	3	8/21/2014	Change FSB truck bay door to roll up and delete seal
B 3.5.4	5	8/21/2014	Change RWST Temperature, Containment Normal and Accident Pressure
B 3.6.2	2	8/21/2014	Change RWST Temperature, Containment Normal and Accident Pressure
B 3.6.3	1	8/21/2014	Change RWST Temperature, Containment Normal and Accident Pressure

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
B 3.6.4	1	8/21/2014	Change RWST Temperature, Containment Normal and Accident Pressure
B 3.7.13	4	8/21/2014	Change FSB truck bay door to roll up and delete seal
BASES UPDATE PACKAGE 47 – 12102014			
B 3.3.3	10	12/10/2014	Mod EC 43617 was not completed so the changed Bases pages are fixed
B 3.7.13	5	12/10/2014	A hi rad signal no longer shuts the truck bay door
BASES UPDATE PACKAGE 48-362015			
B 3.4.3	4	3/6/2015	PT Curves revised for Vacuum Refill
BASES UPDATE PACKAGE 49-8272015			
B 3.4.17	1	8/27/2015	TS Amendment 257 SG Inspection frequencies and tube sample selection
BASES UPDATE PACKAGE 50-10012015			
B 3.4.3	5	10/01/2015	RCS Pressure and Temperature Curves
B 3.4.12	7	10/01/2015	Low Temperature Overpressure Protection
BASES UPDATE PACKAGE 51-02232016			
B3.4.1	2	02/23/2016	Changes consistent with COLR
BASES UPDATE PACKAGE 52-08032016			
B 3.4.3	6	08/03/2016	Correct heading error on first page
B 3.4.12	8	08/03/2016	Correct heading error on first page
BASES UPDATE PACKAGE 53-09302016			
B 3.8.1	8	09/30/2016	Added beginning material regarding non-conservative
BASES UPDATE PACKAGE 54-12062016			
B 3.1.3	2	12/06/2016	TS Amendment 261 exemption from near EOL MTC measurement

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
BASES UPDATE PACKAGE 55-02132018			
B 3.1.3	3	02/20/2018	Editorial correction on page B 3.1.3 - 7
B 3.3.1	5	02/20/2018	Editorial correction on pages B 3.3.1 - 55, - 57
B 3.3.2	7	02/20/2018	Editorial correction on page B 3.3.2 - 46
B 3.3.3	11	02/20/2018	Editorial correction on page B 3.3.3 - 13
B 3.3.4	2	02/20/2018	Editorial correction on page B 3.3.4 - 4
B 3.3.5	4	02/20/2018	Editorial correction on page B 3.3.5 - 6
B 3.4.1	3	02/20/2018	Editorial correction on page B 3.4.1 - 3
B 3.4.3	7	02/20/2018	Editorial correction on pages B 3.4.3 - 1 through - 7
B 3.4.12	9	02/20/2018	Editorial correction on pages B 3.4.12-1 through - 15
B 3.4.17	1	02/20/2018	Replace pages B 3.4.17 - 6 and - 7
B 3.6.6	6	02/20/2018	Editorial correction on page B 3.6.6 - 2
B 3.7.8	4	02/20/2018	Adds reference for EC 40623 on page B 3.7.8 - 7
Appendix C, B 3.1.2	1	02/20/2018	TS Amendment 264 Inter-Unit Transfer of Spent Fuel
BASES UPDATE PACKAGE 56-07312018			
B 3.3.3	12	07/31/2018	Editorial correction on page B 3.3.3 - 17 Editorial correction on page B 3.3.3 - 18
B 3.3.4	3	07/31/2018	Clarification addition on page B 3.3.4 - 5
BASES UPDATE PACKAGE 57-10102018			
B 3.7.9	4	10/10/2018	Revise to address the increased frequency for header swaps.
BASES UPDATE PACKAGE 58-03082019			

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
B 3.8.1	9	03/08/2019	Revise to add the Open Phase Detection System
B.3.8.2	2	03/08/2019	Revise to add the Open Phase Detection System
BASES UPDATE PACKAGE 59-04152019			
B 3.4.1	4	04/15/2019	revised to be consistent with the COLR specified values for TS 3.4.1 and guidance received from Westinghouse
BASES UPDATE PACKAGE 60-08222019			
B 3.0	4	08/22/2019	Revised to implement TSTF 565

TABLE OF CONTENTS

(continued)

TABLE OF CONTENTS (continued)

(continued)

TABLE OF CONTENTS (continued)

(continued)

TABLE OF CONTENTS (continued)

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur and by requiring that fuel centerline temperature stays below the melting temperature.

The restrictions of this SL prevent overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core SLs.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. The hot fuel pellet in the core must not experience centerline fuel melting.

The Reactor Protection System (Ref. 2), in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, RCS flow, Delta I, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

Automatic enforcement of these reactor core SLs is provided by the appropriate operation of the RPS and the steam generator safety valve.

The limitation that the average enthalpy in the hot leg be less than or equal to the enthalpy of saturated liquid also ensures that the , T measured by instrumentation, used in the RPS design as a measure of core power, is proportional to core power.

The SLs represent a design requirement for establishing the RPS trip setpoints identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses (as indicated in the FSAR, Ref. 2) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

The figure provided in the COLR shows the loci of points of thermal power, Reactor Coolant System pressure and vessel inlet temperature for which the calculated DNBR is no less than the Safety Limit DNBR value or the average enthalpy at the vessel exit is less than the enthalpy of saturated liquid.

(continued)

SAFETY LIMITS (continued)

The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. There must be at least a 95% probability at a 95% confidence level that the hot fuel pellet in the core does not experience centerline fuel melting.

The reactor core SLs are used to define the various RPS functions such that the above criteria are satisfied during steady state operations, normal operational transients, and anticipated operation occurrences (AOOs). To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature and Overpower T reactor trip functions. That is, it must be demonstrated that the average enthalpy in the hot leg is less than or equal to the saturation enthalpy and the core exit quality is within the limits defined by the DNBR correlation. Appropriate functioning of the RPS ensures that for variations in the THERMAL POWER, RCS Pressure, RCS average temperature, RCS flow rate, and Delta I that the reactor core SLs will be satisfied during steady state operation, normal operational transients, and AOOs.

The calculation of these limits assumes:

1. $F_{\Delta H}^{RTP} = F_{\Delta H}^{N}$ limit at RTP specified in the COLR;

2. An equivalent average steam generator tube plugging level of less than or equal to 10% (Ref. 3);

3. Reactor coolant system total flow rate of greater than or equal to 364,700 gpm as measured at the plant; and,

4. A reference cosine with a peak of 1.55 for axial power shape.

(continued)

BASES

APPLICABILITY	SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The steam generator safety valves or automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the unit into MODE 3. Setpoints for the reactor trip functions are specified in LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation." In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.
SAFETY LIMIT VIOLATIONS	If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable. The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.
REFERENCES	1. 10 CFR 50, Appendix A. 2. FSAR, Section 7.2.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to 10 CFR 50, Appendix A, GDC 14, "Reactor Coolant Pressure Boundary," and GDC 15, "Reactor Coolant System Design" (Ref. 1), the reactor coolant pressure boundary (RCPB) design conditions are not to be exceeded during normal operation and anticipated operational occurrences (AOOs). Also, in accordance with GDC 28, "Reactivity Limits" (Ref. 1), reactivity accidents, including rod ejection, do not result in damage to the RCPB greater than limited local yielding.

The design pressure of the RCS is 2485 psig. During normal operation and AOOs, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2). To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, according to the ASME Code requirements prior to initial operation when there is no fuel in the core. Following inception of unit operation, RCS components shall be pressure tested, in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB. If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere, raising concerns relative to limits on radioactive releases specified in 10 CFR 50.67, "Reactor Site Criteria" (Ref. 4).

(continued)

APPLICABLE SAFETY ANALYSES

The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the reactor high pressure trip have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a complete loss of external load without a direct reactor trip. During the transient, no control actions are assumed, except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve settings, and nominal feedwater supply is maintained.

The Reactor Protection System setpoints (Ref. 5), together with the settings of the MSSVs, provide pressure protection for normal operation and AOOs. The reactor high pressure trip setpoint is specifically set to provide protection against overpressurization (Ref. 5). The safety analyses for both the high pressure trip and the RCS pressurizer safety valves are performed using conservative assumptions relative to pressure control devices.

More specifically, no credit is taken for operation of the following:

a. Pressurizer Power Operated Relief Valves (PORVs);

b. Atmospheric Dump Valves;

c. Steam Dump System;

d. Reactor Control System;

e. Pressurizer Level Control System; or

f. Pressurizer Spray.

(continued)

BASES

SAFETY LIMITS

The maximum transient pressure allowed in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowed in the RCS piping, valves, and fittings under USAS, Section B31.1 (Ref. 6) is 120% of design pressure. The most limiting of these two allowances is the 110% of design pressure; therefore, the SL on maximum allowable RCS pressure is 2735 psig.

APPLICABILITY

SL 2.1.2 applies in MODES 1, 2, 3, 4, and 5 and in MODE 6 when the reactor vessel head is on because this SL could be approached or exceeded in these MODES due to overpressurization events. The SL is not applicable in MODE 6 when reactor vessel head is removed because the RCS can not be pressurized.

SAFETY LIMIT VIOLATIONS

If the RCS pressure SL is violated when the reactor is in MODE 1 or 2, the requirement is to restore compliance and be in MODE 3 within 1 hour.

Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4).

The allowable Completion Time of 1 hour recognizes the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized.

If the RCS pressure SL is exceeded in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes. Exceeding the RCS pressure SL in MODE 3, 4, or 5 is more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL within 5 minutes. The action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress.

(continued)

BASES

REFERENCES

1. 10 CFR 50, Appendix A.
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.50433
3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IWX-5000.
4. 10 CFR 50.67.
5. FSAR, Section 7.2.
6. USAS B31.1, Standard Code for Pressure Piping, American Society of Mechanical Engineers, 1967.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.8 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

LCO 3.0.1

LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).

LCO 3.0.2

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

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

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

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

(continued)

LCO 3.0.2 (continued)

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

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

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The ACTIONS for not meeting a single LCO adequately manage any increase in plant risk, provided any unusual external conditions (e.g., severe weather, offsite power instability) are considered. In addition, the increased risk associated with simultaneous removal of multiple structures, systems, trains or components from service is assessed and managed in accordance with 10 CFR 50.65(a)(4). Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable.

(continued)

BASES

LCO 3.0.2 (continued)

In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

LCO 3.0.3

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

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

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

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. Planned entry into LCO 3.0.3 should be avoided. If it is not practicable to avoid planned entry into LCO 3.0.3, plant risk should be assessed and managed in accordance with 10 CFR 50.65(a)(4), and the planned entry into LCO 3.0.3 should have less effect on plant safety than other practicable alternatives.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE.

(continued)

LCO 3.0.3 (continued)

This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, Completion Times.

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

a. The LCO is now met.

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

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

The time limits of Specification 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 11 hours, because the total time for reaching MODE 4 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

(continued)

BASES

LCO 3.0.3 (continued)

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.14, "Spent Fuel Pit Water Level." LCO 3.7.14 has an Applicability of "During movement of irradiated fuel assemblies in the Spent Fuel Pit." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.14 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.14 of "Suspend movement of irradiated fuel assemblies in the Spent Fuel Pit" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

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

(continued)

LCO 3.0.4 (continued)

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

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

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

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the risk assessed and managed as stated above. However, there is a small subset of systems and

(continued)

LCO 3.0.4 (continued)

components that have been determined to be more important to risk and the use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these systems and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., RCS specific activity), and may be applied to other Specifications based on NRC plant-specific approval.

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

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry in to the applicable Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

(continued)

BASES

LCO 3.0.4 (continued)

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 3.0.1 or SR 3.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

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

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

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

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

(continued)

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the unit is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

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

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

Specification 5.5.14, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6. Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required.

(continued)

BASES

LCO 3.0.6 (continued)

The cross train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Test Exception LCOs, such as LCO 3.1.8, allow specified Technical Specification (TS) requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Test Exception LCOs is optional. A special operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.

(continued)

LCO 3.0.8

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

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

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

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

LCO 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (the Maintenance Rule) does not address seismic risk. However, use of LCO 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing

(continued)

BASES

LCO 3.0.8 (continued)	Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

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

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO.

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

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known not to be met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a test exception are only applicable when the test exception is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR.

(continued)

SR 3.0.1 (continued)

This allowance includes those SRs whose performance is normally precluded in a given MODE or other specified condition.

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per . . ." interval.

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

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs.

(continued)

SR 3.0.2 (continued)

The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. An example of where SR 3.0.2 does not apply is a Surveillance with a Frequency of "in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions." The requirements of regulations take precedence over the TS. The TS cannot in and of themselves extend a test interval specified in the regulations. Therefore, there is a Note in the Frequency stating, "SR 3.0.2 is not applicable."

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

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

SR 3.0.3

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

This delay period provides adequate time to complete Surveillances that have been missed.

This delay period permits the completion of a surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

(continued)

SR 3.0.3 (continued)

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.
When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

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

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.56(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, ‘Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.’ This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components

(continued)

SR 3.0.3 (continued)

should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

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

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

SR 3.0.4

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

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

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

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that Surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or

(continued)

BASES

SR 3.0.4 (continued)

other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that my (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

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

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

According to GDC 26 (Ref. 1), the reactivity control systems must be redundant and capable of holding the reactor core subcritical when shut down under cold conditions. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion or scram of all shutdown and control rods, assuming that the single rod cluster assembly of highest reactivity worth is fully withdrawn.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable control assemblies and soluble boric acid in the Reactor Coolant System (RCS). The Control Rod System can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the Control Rod System, together with the boration system, provides the SDM during power operation and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The soluble boron system can compensate for fuel depletion during operation and all xenon burnout reactivity changes and maintain the reactor subcritical under cold conditions.

During power operation, SDM control is ensured by operating with the shutdown banks within the limits of LCO 3.1.5, "Shutdown Bank Insertion Limits" and the control banks within the limits of LCO 3.1.6, "Control Bank Insertion Limits."

(continued)

BASES

BACKGROUND (continued)

When the unit is in the shutdown and refueling modes, the SDM requirements are met by means of adjustments to the RCS boron concentration.

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in safety analyses. The safety analysis (Ref. 2) establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption of the highest worth rod stuck out on scram. For MODE 5, the primary safety analysis that relies on the SDM limit is the boron dilution analysis.

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are maintained. This is done by ensuring that:

a. The reactor can be made subcritical from all operating conditions, transients, and Design Basis Events;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departure from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and energy deposition of 225 cal/gm for non-irradiated fuel and 200 cal/gm for irradiated fuel to satisfy requirements for the rod ejection accident); and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

The most limiting accident for the SDM requirements is based on a main steam line break (MSLB), as described in the accident analysis (Ref. 2). The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected steam generator (SG), and consequently the RCS. This results in a reduction of the reactor coolant temperature. The resultant coolant shrinkage causes a reduction in pressure.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. As RCS temperature decreases, the severity of an MSLB decreases until the MODE 5 value is reached. The most limiting MSLB, with respect to potential fuel damage before a reactor trip occurs, is a guillotine break of a main steam line inside containment initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

In addition to the limiting MSLB transient, the SDM requirement must also protect against:

a. Inadvertent boron dilution;

b. An uncontrolled rod withdrawal from subcritical or low power condition;

c. Startup of an inactive reactor coolant pump (RCP); and

d. Rod ejection.

Each of these events is discussed below.

In the boron dilution analysis, the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis. This event is most limiting at the beginning of core life, when critical boron concentrations are highest.

Depending on the system initial conditions and reactivity insertion rate, the uncontrolled rod withdrawal transient is terminated by either a high neutron flux level trip or a overtemperature T

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

trip. In all cases, power level, RCS pressure, linear heat rate, and the DNBR do not exceed allowable limits.

The startup of an inactive RCP will not result in a "cold water" criticality, even if the maximum difference in temperature exists between the SG and the core. The maximum positive reactivity addition that can occur due to an inadvertent RCP start is less than the minimum required SDM. Startup of an idle RCP cannot, therefore, produce a return to power from the hot standby condition.

The ejection of a control rod rapidly adds reactivity to the reactor core, causing both the core power level and heat flux to increase with corresponding increases in reactor coolant temperatures and pressure. The ejection of a rod also produces a time dependent redistribution of core power.

SDM satisfies Criterion 2 of 10 CFR 50.36. Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the unit is operating within the bounds of accident analysis assumptions.

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration.

The MSLB (Ref. 2) and the boron dilution (Ref. 2) accidents are the most limiting analyses that establish the SDM value of the LCO. For MSLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 50.67, "Reactor Site Criteria," limits (Ref. 3). For the boron dilution accident, if the LCO is violated, the minimum required time assumed for operator action to terminate dilution may no longer be applicable.

(continued)

BASES

APPLICABILITY

In MODE 2 with k_{eff} < 1.0 and in MODES 3, 4,and 5, the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration." In MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, Control Bank Insertion Limits.

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a highly concentrated solution, such as that normally found in the boric acid storage tank, or the refueling water storage tank. The operator should borate with the best source available for the plant conditions.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 1 and 2, SDM is verified by observing that the requirements of LCO 3.1.5 and LCO 3.1.6 are met. In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

In MODES 3, 4, and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average loop temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and the low probability of an accident occurring without the required SDM. This allows time for the operator to collect the required data, which includes performing a boron concentration analysis, and complete the calculation.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Chapter 14.

3. 10 CFR 50.67.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

BASES

BACKGROUND

According to GDC 26, GDC 28, and GDC 29 (Ref. 1), reactivity shall be controllable, such that subcriticality is maintained under cold conditions, and acceptable fuel design limits are not exceeded during normal operation and anticipated operational occurrences. Therefore, reactivity balance is used as a measure of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, control rod worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") in ensuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers producing zero net reactivity. Excess reactivity can be inferred from the boron letdown curve (or critical boron curve), which provides an indication of the soluble boron concentration in the Reactor Coolant System (RCS) versus cycle burnup.

(continued)

BASES

BACKGROUND (continued)

Periodic measurement of the RCS boron concentration for comparison with the predicted value with other variables fixed (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations and that the calculational models used to generate the safety analysis are adequate.

In order to achieve the required fuel cycle energy output, the uranium enrichment, in the new fuel loading and in the fuel remaining from the previous cycle, provides excess positive reactivity beyond that required to sustain steady state operation throughout the cycle. When the reactor is critical at RTP and moderator temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, whatever neutron poisons (mainly xenon and samarium) are present in the fuel, and the RCS boron concentration.

When the core is producing THERMAL POWER, the fuel is being depleted and excess reactivity is decreasing. As the fuel depletes, the RCS boron concentration is reduced to decrease negative reactivity and maintain constant THERMAL POWER. The boron letdown curve is based on steady state operation at RTP. Therefore, deviations from the predicted boron letdown curve may indicate deficiencies in the design analysis, deficiencies in the calculational models, or abnormal core conditions, and must be evaluated.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for core reactivity are that the reactivity balance limit ensures plant operation is maintained within the assumptions of the safety analyses.

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Accident evaluations (Ref. 2) are, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod ejection accidents, are very sensitive to accurate prediction of core reactivity.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance additionally ensures that the nuclear methods provide an accurate representation of the core reactivity.

Design calculations and safety analyses are performed for each fuel cycle for the purpose of predetermining reactivity behavior and the RCS boron concentration requirements for reactivity control during fuel depletion.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions at beginning of life (BOL) do not agree to within specified limits then the assumptions used in the reload cycle design analysis or the calculational models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOL, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core burnups beyond BOL, or that an unexpected change in core conditions has occurred.

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from a refueling outage, with the control rods in their normal positions for power operation. The normalization is performed at BOL conditions, so that core reactivity relative to predicted values can be continually monitored and evaluated as core conditions change during the cycle.

Core reactivity satisfies Criterion 2 of 10 CFR 50.36.

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BASES (continued)

LCO

This LCO requires that measured core reactivity is within ± 1% Δk/k of predicted values. During steady state power operation, this comparison includes reactor coolant system boron concentration, control rod position, reactor coolant system average loop temperature, fuel burnup based on gross thermal energy generation, xenon concentration, and samarium concentration.

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled once the core design is fixed. During operation, therefore, the LCO can only be ensured through measurement and tracking, and appropriate actions taken as necessary. Large differences between actual and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the Nuclear Design Methodology are larger than expected. A limit on the reactivity balance of ± 1% Δk/k has been established based on engineering judgment. A 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

When measured core reactivity is within 1% Δk/k of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limit are normally detected by comparing predicted and measured steady state RCS critical boron concentrations, the difference between measured and predicted values would be approximately 100 ppm (depending on the boron worth) before the limit is reached. These values are well within the uncertainty limits for analysis of boron concentration samples, so that spurious violations of the limit due to uncertainty in measuring the RCS boron concentration are unlikely.

APPLICABILITY

The limits on core reactivity must be maintained during MODES 1 and 2 because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed. This Specification does not apply in MODES 3, 4, and 5 because the reactor is shut down and the reactivity balance is not changing.

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BASES

APPLICABILITY (continued)

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron Concentration") ensure that fuel movements are performed within the bounds of the safety analysis. An SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling).

ACTIONS

A.1 and A.2

Should an anomaly develop between measured and predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with input to design calculations. Measured core and process parameters are evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models are reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 7 days is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

Following evaluations of the core design and safety analysis, the cause of the reactivity anomaly may be resolved. If the cause of the reactivity anomaly is a mismatch in core conditions at the time of RCS boron concentration sampling, then a recalculation of the RCS boron concentration requirements may be performed to demonstrate that core reactivity is behaving as expected. If an unexpected physical change in the condition of the core has occurred, it must be evaluated and corrected, if possible. If the cause of the reactivity anomaly is in the calculation technique, then the calculational models must be revised to provide more accurate predictions. If any of these results are demonstrated, and it is concluded that the reactor core is acceptable for continued operation, then the boron letdown curve may be renormalized and power operation may continue. If operational restriction or additional SRs are necessary to ensure the reactor core is acceptable for continued operation, then they must be defined.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

The required Completion Time of 7 days is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

B.1

If the core reactivity cannot be restored to within the 1% $\Delta k/k$ limit, 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 6 hours. If the SDM for MODE 3 is not met, then the boration required by SR 3.1.1.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made during steady state operation because other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance is also performed during physics testing following refueling as an initial check on core conditions and design calculations at BOL. The SR is modified by a Note. The Note indicates that the normalization of predicted core reactivity to the measured value, if performed, must take place within the first 60 effective full power days (EFPD) after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations. The required subsequent Frequency of 31 EFPD based on the slow rate of core changes due to fuel depletion and the presence of other indicators (QPTR, AFD, etc.) for prompt indication of an anomaly.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1 (continued)

As specified in a Note to the FREQUENCY, the inital performance of the SR in MODE 1 after refueling is not required until 60 EFPDs after entering MODE 1.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Chapter 14.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11 (Ref. 1), the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a negative MTC over the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the beginning of life (BOL) MTC is less than zero when THERMAL POWER is at RTP. The actual value of the MTC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons to yield an MTC at BOL within the range analyzed in the plant accident analysis. The end of life (EOL) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOL limit.

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting conditions assumed in the FSAR accident and transient analyses.

(continued)

BASES

BACKGROUND (continued)

If the LCO limits are not met, the unit response during transients may not be as predicted. The core could violate criteria that prohibit a return to criticality, or the departure from nucleate boiling ratio criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

The SRs for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits, since this coefficient changes slowly, due principally to the reduction in RCS boron concentration associated with fuel burnup.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2); and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

The FSAR, Chapter 14 (Ref. 2), contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the most positive value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding (Ref. 3).

The consequences of accidents that cause core overheating must be evaluated when the MTC is positive. Such accidents include the rod withdrawal transient from either zero (Ref. 2) or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The consequences of accidents that cause core overcooling must be evaluated when the MTC is negative. Such accidents include sudden feedwater flow increase and sudden decrease in feedwater temperature.

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is the BOL or EOL. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC values are bounded in reload safety evaluations assuming steady state conditions at BOL and EOL. An EOL measurement is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOL value, in order to confirm reload design predictions.

MTC satisfies Criterion 2 of 10 CFR 50.36. Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the original accident analysis during operation.

Assumptions made in safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The MTC is most positive near BOL; this upper bound must not be exceeded. This maximum upper limit occurs at BOL, all rods out (ARO), hot zero power conditions.

(continued)

BASES

LCO (continued)

At EOL the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance checks at BOL and EOL on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

The LCO establishes a maximum positive value that cannot be exceeded. The BOL positive limit and the EOL negative limit are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled CONTROL ROD assembly or group withdrawal) will not violate the assumptions of the accident analysis. The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents using the MTC as an analysis assumption are initiated from these MODES.

ACTIONS

A.1

If the BOL MTC limit is violated, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits. The MTC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required bank withdrawal limits.

(continued)

BASES

ACTIONS

A.1 (continued)

As cycle burnup is increased, the RCS boron concentration will be reduced. The reduced boron concentration causes the MTC to become more negative. Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

B.1

If the required administrative withdrawal limits at BOL are not established within 24 hours, the unit must be brought to MODE 2 with $k_{eff} < 1.0$ to prevent operation with an MTC that is more positive than that assumed in safety analyses.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

C.1

Exceeding the EOL MTC limit means that the safety analysis assumptions for the EOL accidents that use a bounding negative MTC value may be invalid. If the EOL MTC limit is exceeded, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR requires measurement of the MTC at BOL prior to entering MODE 1 in order to demonstrate compliance with the most positive MTC LCO. Meeting the limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

The BOL MTC value for ARO will be inferred from isothermal temperature coefficient measurements obtained during the physics tests after refueling. The ARO value can be directly compared to the BOL MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

SR 3.1.3.2

In similar fashion, the LCO demands that the MTC be less negative than the specified value for EOL full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should necessarily be less negative than the EOL LCO limit. The 300 ppm SR value is sufficiently less negative than the EOL LCO limit value to ensure that the LCO limit will be met when the 300 ppm Surveillance criterion is met.

SR 3.1.3.2 is modified by four Notes that include the following requirements:

1. This SR is not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm. This note alters the FREQUENCY to “Once each cycle within 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP ARO boron concentration of 300 ppm.”

2. SR 3.1.3.2 is not required to be performed by measurement provided that the benchmark criteria in WCAP-13749-P-A (Ref. 4) are satisfied and the Revised Predicted MTC satisfies the 300 ppm surveillance limit specified in the COLR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.2 (continued)

3. If the 300 ppm Surveillance limit is exceeded, it is possible that the EOL limit on MTC could be reached before the planned EOL. Because the MTC changes slowly with core depletion, the Frequency of 14 effective full power days is sufficient to avoid exceeding the EOL limit. This note establishes a new required action and completion time. The required action, verify the MTC is within the COLR lower limit (which is a repeat of the surveillance), occurs when the existing surveillance requirement (i.e., to verify the MTC is more positive than the limit specified in the COLR for a 300 ppm boron concentration) fails. The frequency is 14 EFPD after the initial surveillance test fails and every 14 EFPD thereafter.

4. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is more positive than the 60 ppm Surveillance limit, the EOL limit will not be exceeded because of the gradual manner in which MTC changes with core burnup. This note acts to limit the action requirement in Note 2. It allows the action to repeat the surveillance to be terminated if the MTC measured at the equivalent of equilibrium RTP-ARO boron concentration of <60 ppm is less negative than the 60 ppm surveillance limit specified in the COLR.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Chapter 14.

3. WCAP 9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

4. WCAP-13749-P-A. “Safety Evaluation Supporting the Conditional Exemption of the Most Negative EOL Moderator Temperature Coefficient Measurement,” March 1997.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (i.e., trippability) of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM.

The applicable criteria for these reactivity and power distribution design requirements are GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref. 2).

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved by their control rod drive mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately $^{5}/_{8}$ inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

(continued)

BASES

BACKGROUND (continued)

The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs may consist of two groups that are moved in a staggered fashion, but always within one step of each other. IP3 has four control banks and four shutdown banks.

The shutdown banks are maintained either in the fully inserted or fully withdrawn position. The control banks are moved in an overlap pattern, using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with control bank A. Control bank A stops at the position of maximum withdrawal, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues until control banks A, B, and C are at the fully withdrawn position, and control bank D is at the desired position. The insertion sequence is the opposite of the withdrawal sequence. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems, which are the Bank Demand Position Indication System (commonly called group step counters) and the Individual Rod Position Indication (IRPI) System.

The Bank Demand Position Indication System counts the pulses from the rod control system that moves the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is highly precise (± 1 step or ± $^5/_8$ inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

(continued)

BASES

BACKGROUND (continued)

The IRPI System provides an indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a coil stack located above the stepping mechanisms of the control rod magnetic jacks, external to the pressure housing, but concentric with the rod travel. When the associated control rod is at the bottom of the core, the magnetic coupling between the primary and secondary coil winding of the detector is small and there is a small voltage induced in the secondary. As the control rod is raised by the magnetic jacks, the relatively high permeability of the lift rod causes an increase in magnetic coupling. Thus, an analog signal proportional to rod position is obtained. The rod position maximum uncertainty is ± 12 steps (± 7.5 inches). Misalignment limit of 12 steps precludes a rod misalignment of > 15 inches when instrument error is considered. An indicated misalignment limit of 24 steps precludes a rod misalignment of > 22.5 inches when instrument error is considered. Additional misalignment is allowed near the fully withdrawn position because the top of the active core (approximately 225 steps) is less than the fully withdrawn position.

APPLICABLE SAFETY ANALYSES

Control rod misalignments are analyzed in Reference 4. The acceptance criteria for addressing control rod inoperability or misalignment are that:

a. There be no violations of:

   1. specified acceptable fuel design limits, or

   2. Reactor Coolant System (RCS) pressure boundary integrity; and

b. The core remains subcritical after accident transients.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The analysis identifies six possible modes of control rod failure and translates these failure mechanisms into eight analyzed cases. The eight cases are analyzed at full and part power conditions, and they fall into the following categories:

1. One or more rods misaligned out.
2. One or more rods misaligned in.
3. One group misaligned in.
4. One group misaligned out.
5. One group misaligned out with another group from the same cabinet misaligned in.
6. One entire bank misaligned out with the other bank from the same cabinet misaligned in.

The first six analyses are perfomed with the rods at their insertion limits. The next two analyses are for positions at other than the insertion limits.

7. All rods inserted below rod insertion limit.
8. One or more rods misaligned from all-rods-out position.

These eight conditions were applied to 248 possible cases, representing a wide variety of plant conditions involving allowable deviation below 85% RTP (± 24 steps) and above 85% RTP (±12 steps). In all cases, the resulting peaking factor increase was within required limits. Core subcriticality is assured through evaluation of shutdown margin versus rod worth for each reload cycle.

The allowable deviation increases when the rods are near their fully withdrawn limit, as shown in Table 3.1.4-1. This is due to the fact that the top of the active core is at an equivalent rod position of about 224 steps withdrawn. Therefore, the effect of increased deviation in this region is reduced for bank demand positions within 12 steps of the top of the core and higher.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local linear heat rates (LHRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved.

Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified directly by incore mapping. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of 10 CFR 50.36.

LCO

The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The OPERABILITY requirements also ensure that the RCCAs and banks maintain the correct power distribution and rod alignment.

To ensure that individual rods are properly aligned with their associated group step counter demand position, the following limits are placed on individual rod positions:

(continued))

BASES

LCO (continued)

a. When THERMAL POWER is > 85% RTP, the difference between each individual indicated rod position and its group step counter demand position shall be within the limits specified in Table 3.1.4-1 for the group step counter demand position; and

b. When THERMAL POWER is ≤ 85% RTP, the difference between each individual indicated rod position and its group step counter demand position shall be within 24 steps.

These limits ensure analysis assumptions for SDM and peaking factors are met because an indicated misalignment of 12 steps precludes a rod misalignment of > 15 inches when instrument error is considered. An indicated misalignment limit of 24 steps precludes a rod misalignment of > 22.5 inches when instrument error is considered.

Failure to meet the requirements of this LCO may produce unacceptable power peaking factors and LHRs, or unacceptable SDMs, all of which may constitute initial conditions inconsistent with the safety analysis (Ref. 4).

APPLICABILITY

The requirements on RCCA OPERABILITY and alignment are applicable in MODES 1 and 2 because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the control rods are typically bottomed and the reactor is shut down and not producing fission power. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM in MODES 3, 4, and 5 and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during refueling.

(continued)

BASES (continued)

ACTIONS

A.1.1 and A.1.2

When one or more rods are untrippable, there is a possibility that the required SDM may be adversely affected. Required Actions A.1.1 and A.1.2 apply if either SR 3.1.4.2 or SR 3.1.4.3 are not met. Under these conditions, it is important to determine the SDM, and if it is less than the required value, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating emergency boration and restoring SDM.

In this situation, SDM verification must include the worth of the untrippable rod, as well as a rod of maximum worth.

A.2

If the untrippable rod(s) cannot be restored to OPERABLE status, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

B.1

When a rod becomes misaligned, it can usually be moved and is still trippable. If the rod can be realigned within the Completion Time of 1 hour, local xenon redistribution during this short interval will not be significant, and operation may proceed without further restriction. If all individual indicated rod positions are within 24 steps of their group step counter demand position, the LCO may be met by reducing reactor power to ≤ 85% RTP.

(continued)

BASES

ACTIONS

B.1 (continued)

An alternative to realigning a single misaligned RCCA to the group average position is to align the remainder of the group to the position of the misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits." The Completion Time of 1 hour gives the operator sufficient time to adjust the rod positions in an orderly manner. A one-hour allowance for thermal stabilization of rod position instrumentation, as discussed in SR 3.1.4.1, applies when determining if a rod is misaligned.

B.2.1.1 and B.2.1.2

With a misaligned rod, SDM must be verified to be within limit or boration must be initiated to restore SDM to within limit.

In many cases, realigning the remainder of the group to the misaligned rod may not be desirable. For example, realigning control bank B to a rod that is misaligned 20 steps from the top of the core would require a significant power reduction, since control bank D must be moved fully in and control bank C must be moved in to approximately 100 to 115 steps.

Power operation may continue with one RCCA trippable but misaligned, provided that SDM is verified within 1 hour. The Completion Time of 1 hour represents the time necessary for determining the actual unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration.

(continued)

BASES

ACTIONS (continued)

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6

For continued operation with a misaligned rod, RTP must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible.

Reduction of power to 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded. The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

Verifying that $F_Q(Z)$ and $F^N_{\Delta H}$ are within the required limits ensures that current operation at 75% RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain flux maps of the core power distribution using the incore flux mapping system and to calculate $F_Q(Z)$ and $F^N_{\Delta H}$.

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analysis to determine that core limits will not be exceeded during a Design Basis Event for the duration of operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

The analysis specified by Required Action B.2.6 must address the potential ejected rod worth, non-uniform fuel depletion, associated transient power distribution peaking factors and accidents. The following issues must also be addressed:

(continued)

BASES

ACTIONS

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6 (continued)

a. Rod cluster control assembly insertion characteristics;

b. Rod Cluster Control Assembly Misalignment;

c. Loss of reactor coolant from small ruptured pipes or from cracks in large pipes which actuates the emergency core cooling system;

d. Single rod cluster control assembly withdrawal at full power;

e. Major reactor coolant system pipe ruptures (loss of coolant accident);

f. Major Secondary system pipe rupture; and

g. Rupture of a control rod drive mechanism housing.

C.1

When Required Actions cannot be completed within their Completion Time, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which obviates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging the plant systems.

D.1.1 and D.1.2

More than one control rod becoming misaligned from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron

(continued)

BASES

ACTIONS

D.1.1 and D.1.2 (continued)

concentration to provide negative reactivity, as described in the Bases for LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the boric acid pumps. Boration will continue until the required SDM is restored.

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the unit conditions fall outside of the accident analysis assumptions. Since automatic bank sequencing would continue to cause misalignment, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual rod positions are within alignment limits at a Frequency of 12 hours provides a history that allows the operator to detect a rod that is beginning to deviate from its expected position. Rod position may be verified using normal indication, direct readings using a digital voltmeter, or the plant computer. The specified Frequency takes into account other rod position information that is continuously available to the operator in the control room, so that during actual rod motion, deviations can immediately be detected. This SR is not required to be met for an individual control rod until 1 hour after

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1 (continued)

completion of movement of that rod. This allowance is needed because it provides time for thermal stabilization of rod position instrumentation. This allowance is acceptable because individual rod position indicators may not accurately reflect control rod position prior to thermal stabilization and there is a presumption that individual control rods will move with their group.

SR 3.1.4.2

Verifying each control rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2, tripping each control rod would result in radial or axial power tilts, or oscillations. Exercising each individual control rod every 92 days provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each control rod by 10 steps in a single direction will not cause radial or axial power tilts, or oscillations, to occur. This SR requires that control rods be inserted or withdrawn by at least 10 steps which is sufficient to ensure that rod movement can be confirmed by individual rod position indicators. Administrative controls and Technical Specification limits ensure that control rod insertion limits are met. The 92 day Frequency takes into consideration other information available to the operator in the control room and SR 3.1.4.1, which is performed more frequently and adds to the determination of OPERABILITY of the rods.

Between required performances of SR 3.1.4.2 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be immovable, but remains trippable and aligned, the control rod(s) is considered to be OPERABLE. At any time, if a control rod(s) is immovable, a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.3

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times prior to reactor criticality, after reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time. This testing is performed with all RCPs operating and the average moderator temperature ≥ 500°F to simulate a reactor trip under actual conditions.

This Surveillance is performed during a plant outage, due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance was performed with the reactor at power.

REFERENCES

1. 10 CFR 50, Appendix A.
2. 10 CFR 50.46.
3. FSAR, Chapter 14.
4. WCAP-14668, Conditional Extension of the Rod Misalignment Technical Specification for Indian Point Unit 3, October 1996 (Proprietary).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth, SDM and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs may consist of two groups that are moved in a staggered fashion, but always within one step of each other. IP3 has four control banks and four shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally automatically controlled by the Rod Control System, but they can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating).

(continued)

BASES

BACKGROUND (continued)

The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations.

Hence, they are not capable of adding a large amount of positive reactivity. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature, power, and fuel depletion. The design calculations are performed with the assumption that the shutdown banks are withdrawn first. The shutdown banks can be fully withdrawn without the core going critical. This provides available negative reactivity in the event of boration errors. The shutdown banks are controlled manually by the control room operator. During normal unit operation, the shutdown banks are either fully withdrawn or fully inserted. The shutdown banks must be completely withdrawn from the core, prior to withdrawing any control banks during an approach to criticality. The shutdown banks are then left in this position until the reactor is shut down. They affect core power and burnup distribution, and add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown banks and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown banks shall be at or above their insertion limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core, as allowed by LCO 3.1.6, "Control Bank Insertion Limits." The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM),") following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at rated no load temperature (Ref. 3).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The shutdown bank insertion limit also limits the reactivity worth of an ejected shutdown rod when at power.

The acceptance criteria for addressing shutdown and control rod bank insertion limits and inoperability or misalignment is that:

a. There be no violations of:

   1. Specified acceptable fuel design limits, or

   2. RCS pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown bank insertion limits affect safety analysis involving core reactivity and SDM (Ref. 3).

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of 10 CFR 50.36.

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. The applicability in MODE 2 begins prior to initial control bank withdrawal, during an approach to criticality, and continues throughout MODE 2, until all control bank rods are again fully inserted by reactor trip or by shutdown. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

(continued)

BASES

APPLICABILITY (continued)

The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 4, 5, or 6, the shutdown banks are normally fully inserted in the core and contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

The Applicability requirements have been modified by a Note indicating the LCO requirement is suspended during SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO.

ACTIONS

A.1.1, A.1.2 and A.2

When one or more shutdown banks is not within insertion limits, 2 hours is allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced, with one or more of the shutdown banks not within their insertion limits. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

B.1

If the shutdown banks cannot be restored to within their insertion limits within 2 hours, the unit must be brought to a MODE where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that the shutdown banks are within their insertion limits prior to an approach to criticality ensures that when the reactor is critical, or being taken critical, the shutdown banks will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. This SR and Frequency ensure that the shutdown banks are withdrawn before the control banks are withdrawn during a unit startup.

Since the shutdown banks are positioned manually by the control room operator, a verification of shutdown bank position at a Frequency of 12 hours, after the reactor is taken critical, is adequate to ensure that they are within their insertion limits. Also, the 12 hour Frequency takes into account other information available in the control room for the purpose of monitoring the status of shutdown rods.

REFERENCES

1. 10 CFR 50, Appendix A.

2. 10 CFR 50.46.

3. FSAR, Chapter 14.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available SDM, and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs may consist of two groups that are moved in a staggered fashion, but always within one step of each other. IP3 has four control banks and four shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control bank insertion limits are specified in the COLR. The control banks are required to be at or above the insertion limit. The COLR also indicates how the control banks are moved in an overlap pattern. Overlap is the distance traveled together by two control banks. The fully withdrawn position is defined in the COLR.

(continued)

BASES

BACKGROUND (continued)

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Rod Control System, but can also be manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting).

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, "Rod Group Alignment Limits", LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, "Control Bank Insertion Limits", LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Protection System (RPS) trip function.

APPLICABLE SAFETY ANALYSES

The shutdown and control bank insertion limits, AFD, and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accident requiring termination by an RTS trip function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

a. There be no violations of:

   1. specified acceptable fuel design limits, or

   2. Reactor Coolant System pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3).

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Ref. 3).

Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths.

The control and shutdown bank insertion limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 3).

The insertion limits satisfy Criterion 2 of 10 CFR 50.36 because they are initial conditions assumed in the safety analysis.

(continued)

BASES (continued)

LCO

The limits on control banks sequence, overlap, and physical insertion, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is maintained, and ensuring adequate negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion.

APPLICABILITY

The control bank sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions. Applicability in MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

The applicability requirements have been modified by a Note indicating the LCO requirements are suspended during the performance of SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the control bank to move below the LCO limits, which would violate the LCO.

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2

When the control banks are outside the acceptable insertion limits, they must be restored to within those limits. This restoration can occur in two ways:

a. Reducing power to be consistent with rod position; or

b. Moving rods to be consistent with power.

(continued)

BASES

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2 (continued)

Also, verification of SDM or initiation of boration to regain SDM is required within 1 hour, since the SDM in MODES 1 and 2 normally ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") has been upset. If control banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

Similarly, if the control banks are found to be out of sequence or in the wrong overlap configuration, they must be restored to meet the limits.

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability.

The allowed Completion Time of 2 hours for restoring the banks to within the insertion, sequence, and overlaps limits provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

C.1

If Required Actions A.1 and A.2, or B.1 and B.2 cannot be completed within the associated Completion Times, the plant must be brought to MODE 3, where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits.

The estimated critical position (ECP) depends upon a number of factors, one of which is xenon concentration. If the ECP was calculated for a time different from when criticality occurs, xenon concentration could change to make the ECP substantially in error. Conversely, determining the ECP immediately before criticality could be an unnecessary burden. There are a number of unit parameters requiring operator attention at that point. Verifying the ECP calculation within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the ECP calculation with other startup activities.

SR 3.1.6.2

Verification of the control bank insertion limits at a Frequency of 12 hours is sufficient to detect control banks that may be approaching the insertion limits since, normally, very little rod motion occurs in 12 hours.

SR 3.1.6.3

When control banks are maintained within their insertion limits as checked by SR 3.1.6.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. A Frequency of 12 hours is consistent with the insertion limit check above in SR 3.1.6.2.

REFERENCES

1. 10 CFR 50, Appendix A.
2. 10 CFR 50.46.
3. FSAR, Chapter 14.

B 3.1 REACTIVITY CONTROL SYSTEM

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

According to GDC 13 (Ref. 1), instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.7 is required for rod cluster control assemblies (RCCAs), or rods, to ensure OPERABILITY of position indicators to determine control rod positions and thereby ensure compliance with the rod alignment and insertion limits.

The OPERABILITY, including position indication, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM. Rod position indication is required to assess OPERABILITY and misalignment.

Mechanical or electrical failures may cause a rod to become inoperable or to become misaligned from its group. Rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms. The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control.

(continued)

BASES

BACKGROUND (continued)

The axial position of shutdown rods and control rods are determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) and the Individual Rod Position Indication (IRPI) System.

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± $^{5}/_{8}$ inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The IRPI System provides an accurate indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a coil stack located above the stepping mechanisms of the control rod magnetic jacks, external to the pressure housing, but concentric with the rod travel. When the associated control rod is at the bottom of the core, the magnetic coupling between the primary and secondary coil winding of the detector is small and there is a small voltage induced in the secondary. As the control rod is raised by the magnetic jacks, the relatively high permeability of the lift rod causes an increase in magnetic coupling. Thus, an analog signal proportional to rod position is obtained. An indicated misalignment limit of 12 steps precludes a rod misalignment of > 15 inches when instrument error is considered. An indicated misalignment limit of 24 steps precludes a rod misalignment of > 22.5 inches when instrument error is considered.

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2), with control orshutdown rods operating outside their

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "Rod Group Alignment Limits"). Rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

The rod position indicator channels satisfy Criterion 2 of 10 CFR 50.36. The control rod position indicators monitor rod position, which is an initial condition of the accident.

LCO

LCO 3.1.7 specifies that one IRPI System and one Bank Demand Position Indication System be OPERABLE for each rod. For the rod position indicators to be OPERABLE, the SR of the LCO and the following must be met:

a. The IRPI System indicates within the required number of steps of the group step counter demand position as required by LCO 3.1.4, "Rod Group Alignment Limits";

b. For the IRPI System there are no failed coils; and

c. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the IRPI System.

The agreement limit between the Bank Demand Position Indication System and the IRPI System indicates that the Bank Demand Position Indication System is adequately calibrated, and can be used for indication of the measurement of control rod bank position.

(continued)

BASES

LCO (continued)

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single rod, ensures high confidence that the position uncertainty of the corresponding rod group is within the assumed values used in the analysis (that specified rod group insertion limits).

These requirements ensure that rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged.

OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

APPLICABILITY

The requirements on the IRPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable rod position indicator and each demand position indicator. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

A.1

When one IRPI channel per group fails, the position of the rod may still be determined indirectly by use of the movable incore detectors. The Required Action may also be satisfied by ensuring at least once per 8 hours that F_Q satisfies LCO 3.2.1, $F\Delta H$ satisfies LCO 3.2.2, and shutdown MARGIN is within the limits provided in the COLR, provided the nonindicating rods have not been moved.

(continued)

BASES

ACTIONS

A.1 (continued)

Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of C.1 or C.2 below is required.

Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

Note that an IRPI channel is not inoperable if rod position can be determined using a digital voltmeter in lieu of the installed indicators.

A.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 2).

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

B.1, B.2, B.3 and B.4

When more than one IRPI per group fail, additional actions are necessary to ensure that acceptable power distribution limits are maintained, minimum SDM is maintained, and the potential effects of rod misalignment on associated accident analyses are limited. Placing the Rod Control System in manual assures unplanned rod motion will not occur. Together with the indirect position determination available via movable incore detectors will minimize the potential for rod misalignment. The immediate Completion Time for placing the Rod Control System in manual reflects the urgency with which unplanned rod motion must be prevented while in this condition.

(continued)

ACTIONS

B.1, B.2, B.3 and B.4 (continued)

Monitoring and recording reactor coolant T_{avg} help assure that significant changes in power distribution and SDM are avoided. The once per hour Completion Time is acceptable because only minor fluctuations in RCS Temperature are expected at steady state plant operating conditions.

The position of the rods may be determined indirectly by use of the movable incore detectors. The Required Action may also be satisfied by ensuring at least once per 8 hours that F_Q satisfies LCO 3.2.1, $F^N \Delta H$ satisfies LCO 3.2.2, and SHUTDOWN MARGIN is within the limits provided in the COLR, provided the nonindicating rods have not been moved. Verification of control rod position once per 8 hours is adequate for allowing ocntinued full power operation of for a lmited, 24 hour period, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small. The 24 hour Completion Time provides sufficient time to troubleshoot and restore the PRPS system to operation while avoiding the plant challenges associated with a shutdown without full rod position indication.

Based on operating experience, normal power operation does not require excessive rod movement. If one or more rods have been significantly moved, the Required Action of C.1 or C.2 below is required.

C.1 and C.2

These Required Actions clarify that when one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction, since the position was last determined, the Required Actions of A.1 and A.2 are still appropriate but must be initiated promptly under Required Action C.1 to begin verifying that these rods are still properly positioned, relative to their group positions.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

If, within 4 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation at ≥ 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 4 hours provides an acceptable period of time to verify the rod positions.

D.1.1 and D.1.2

With one demand position indicator per bank inoperable (i.e., bank demand position cannot be determined), the rod positions can be determined by the IRPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE and the most withdrawn rod and the least withdrawn rod are ≤ 12 steps apart when > 85% RTP and ≤ 24 steps apart when ≤ 85% RTP within the allowed Completion Time of once every 8 hours is adequate.

D.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factor limits. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions C.1.1 and C.1.2 or reduce power to ≤ 50% RTP.

E.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verification that the IRPI agrees with the demand position within the required number of steps ensures that the IRPI is operating correctly. This surveillance is performed prior to reactor criticality after each removal of the reactor vessel head because there is a potential for unnecessary plant transients if the SR were performed with the reactor at power.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Chapter 14.

3. WCAP-14668, Conditional Extension of the Rod Misalignment Technical Specification for Indian Point Unit 3, October 1996 (Proprietary).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions – MODE 2

BASES

BACKGROUND

The primary purpose of the MODE 2 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow certain PHYSICS TESTS to be performed.

Section XI of 10 CFR 50, Appendix B (Ref. 1), requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program (Ref. 3) are to:

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict unit response; and

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design.

To accomplish these objectives, testing is performed prior to initial criticality, during startup, during low power operations, during power ascension, and after each refueling. The PHYSICS TESTS requirements for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions and that the core can be operated as designed (Ref. 4).

(continued)

BASES

BACKGROUND (continued)

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include all information necessary to permit a detailed execution of the testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures and test results are approved prior to continued power escalation and long term power operation.

The PHYSICS TESTS required for reload fuel cycles (Ref.4) in MODE 2 are listed below:

a. Critical Boron Concentration - Control Rods Withdrawn;
b. Control Rod Worth;
c. Isothermal Temperature Coefficient (ITC); and
d. Neutron Flux Symmetry.

These and other supplementary tests may be required to calibrate the nuclear instrumentation or to diagnose operational problems. These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance.

APPLICABLE SAFETY ANALYSES

The fuel is protected by LCOs that preserve the initial conditions of the core assumed during the safety analyses. The methods for development of the LCOs that are excepted by this LCO are described in the Westinghouse Reload Safety Evaluation Methodology Report (Ref. 5). These PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating control or process variables to deviate from their LCO limitations.

The FSAR defines requirements for initial testing of the facility, including PHYSICS TESTS. Requirements for reload fuel cycle PHYSICS TESTS are defined in ANSI/ANS-19.6.1-1985 (Ref. 4). Although these PHYSICS TESTS are generally accomplished within the limits for all LCOs, conditions may occur when one or more LCOs must be suspended to make completion of PHYSICS TESTS possible or practical.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

This is acceptable as long as the fuel design criteria are not violated. When one or more of the requirements specified in LCO 3.1.3, "Moderator Temperature Coefficient (MTC)," LCO 3.1.4, "Group Rod Alignments", LCO 3.1.5, "Shutdown Bank Insertion Limits", LCO 3.1.6, "Control Bank Insertion Limits", and LCO 3.4.2, "RCS Minimum Temperature for Criticality", are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the power level is limited to ≤ 5% RTP, the reactor coolant temperature is kept ≥ 540°F, and SDM is kept within the limits specified in the COLR for low power physics tests.

The PHYSICS TESTS include measurement of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the unit safety analyses. Also involved are Rod Cluster Control Assemblies (RCCAs) or control rods (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR. PHYSICS TESTS meet the criteria for inclusion in the Technical Specifications, since the components and process variable LCOs suspended during PHYSICS TESTS meet Criteria 1, 2, and 3 of 10 CFR 50.36.

Reference 6 allows special test exceptions (STEs) to be included as part of the LCO that they affect. It was decided, however, to retain this STE as a separate LCO because it was less cumbersome and provided additional clarity.

LCO

This LCO allows the reactor MTC to be outside its specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. Operation beyond specified limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

(continued)

BASES

LCO (continued)

The requirements of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended during the performance of PHYSICS TESTS provided:

a. RCS lowest loop average temperature is ≥ 540 °F;

b. SDM is within the limit specified in the COLR; and

c. THERMAL POWER is ≤ 5% RTP.

APPLICABILITY

This LCO is applicable in MODE 2 when performing low power PHYSICS TESTS. The applicable PHYSICS TESTS are performed in MODE 2 at HZP.

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

B.1

When THERMAL POWER is > 5% RTP, as indicated on power range instruments, the only acceptable action is to open the reactor trip breakers (RTBs) to prevent operation of the reactor beyond its design limits. Immediately opening the RTBs will shut down the reactor and prevent operation of the reactor outside of its design limits.

(continued)

BASES

ACTIONS (continued)

C.1

When the RCS lowest T_{avg} is < 540°F, the appropriate action is to restore T_{avg} to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring T_{avg} to within limits without allowing the plant to remain in an unacceptable condition for an extended period of time. Operation with the reactor critical and with temperature below 540°F could violate the assumptions for accidents analyzed in the safety analyses.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within an additional 15 minutes. The Completion Time of 15 additional minutes is reasonable, based on operating experience, for reaching MODE 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

The power range and intermediate range neutron detectors must be verified to be OPERABLE in MODE 2 by LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation." The frequency is specified in LCO 3.3.1. A CHANNEL OPERATIONAL TEST is normally performed on each power range and intermediate range channel prior to initiation of the PHYSICS TESTS. This will ensure that the RPS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.8.2

Verification that the RCS lowest loop T_{avg} is ≥ 540°F will ensure that the unit is not operating in a condition that could invalidate the safety analyses. Verification of the RCS temperature at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

SR 3.1.8.3

Verification that THERMAL POWER is ≤ 5% RTP will ensure that the plant is not operating in a condition that could invalidate the safety analysis. Verification of THERMAL POWER at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

SR 3.1.8.4

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.4 (continued)

Using the ITC accounts for Doppler reactivity in this calculation when the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident occurring without the required SDM.

REFERENCES

1. 10 CFR 50, Appendix B, Section XI.

2. 10 CFR 50.59.

3. Regulatory Guide 1.68, Revision 2, August, 1978.

4. ANSI/ANS-19.6.1-1985, December 13, 1985.

5. WCAP-9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology Report," July 1985.

6. WCAP-11618, including Addendum 1, April 1989.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

During power operation, the global power distribution is limited by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT TILT POWER RATIO (QPTR)," which are directly and continuously measured process variables. These LCOs, along with LCO 3.1.6, "Control Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution.

$F_Q(Z)$ is measured periodically using the incore detector system. These measurements are generally taken with the core at or near steady state conditions.

Using the measured three dimensional power distributions, it is possible to derive a measured value for $F_Q(Z)$. However, because this value represents a steady state condition, it does not include the variations in the value of $F_Q(Z)$ that are present during nonequilibrium situations.

Core monitoring and control under nonsteady state conditions are accomplished by operating the core within the limits of the appropriate LCOs, including the limits on AFD, QPTR, and control rod insertion.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident (LOCA), the peak cladding temperature must not exceed 2200^0F (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a departure from nucleate boiling (DNB) condition;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 225 calories/gram for non-irradiated fuel and 200 calories/gram for irradiated fuel (Ref. 2); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

Limits on $F_Q(Z)$ ensure that the value of the initial total peaking factor assumed in the accident analyses remains valid. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the peak cladding temperature is typically most limiting.

$F_Q(Z)$ limits assumed in the LOCA analysis are typically limiting relative to (i.e., lower than) the $F_Q(Z)$ limit assumed in safety analyses for other postulated accidents. Therefore, this LCO provides conservative limits for other postulated accidents.

$F_Q(Z)$ satisfies Criterion 2 of 10 CFR 50.36.

(continued)

BASES (continued)

LCO

The Heat Flux Hot Channel Factor, $F_Q(Z)$, shall be limited by the following relationships:

$F_Q(Z) \leq (FQ/P) K(Z)$ For P> 0.5

$F_Q(Z) \leq (FQ/0.5) K(Z)$ For P≤ 0.5

where: FQ is the $F_Q(Z)$ limit at RTP provided in the COLR,

K(Z) is the normalized $F_Q(Z)$ as a function of core height provided in the COLR, and

P= THERMAL POWER/RTP

The current IP3 specific values of FQ and K(Z) are given in the COLR.

An $F_Q(Z)$ evaluation requires obtaining an incore flux map in MODE 1. From the incore flux map results we obtain the measured value ($F_Q^M(Z)$) of $F_Q(Z)$. Then,

$F_Q(Z) = F_Q^M(Z)\ 1.0815$

where 1.0815 is a factor that accounts for fuel manufacturing tolerances and flux map measurement uncertainty. This correction factor for the measured value of total peaking factor $F_Q^M(Z)$ is for the three percent needed to account for manufacturing tolerances and this value is further increased by five percent to account for measurement error (75% available thimbles).

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures exceeding 2200^0F during either a large or small break LOCA.

This LCO requires operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a

(continued)

LCO (continued)

manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F_Q(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required.

Violating the LCO limits for $F_Q(Z)$ produces unacceptable consequences if a design basis event occurs while $F_Q(Z)$ is outside its specified limits.

APPLICABILITY

The $F_Q(Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q(Z)$ exceeds its limit, maintains an acceptable absolute power density. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time. The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of $F_Q(Z)$ and would require power reductions within 15 minutes of the $F_Q(Z)$ determination, if necessary, to comply with the decreased maximum allowable power level. Decreases in the $F_Q(Z)$ would allow increasing the maximum allowable power level and increasing power up to this revised limit.

A.2

A reduction of the Power Range Neutron Flux — High trip setpoints by ≥ 1% for each 1% by which $F_Q(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the

(continued)

BASES

ACTIONS

A.2 (continued)

preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Power Range Neutron Flux - High trip setpoints initially determined by Required Action A.2 may be affected by subsequent determinations of $F_Q(Z)$ and would require reductions for the Power Range Neutron Flux - High trip setpoints within 72 hours of the $F_Q(Z)$ determination, if necessary, to comply with the decreased maximum allowable power level. Decreases in the $F_Q(Z)$ would allow increasing the Power Range Neutron Flux - High trip setpoints.

A.3

Reduction in the Overpower ΔT trip setpoints by ≥ 1% for each 1% by which $F_Q(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Overpower ΔT trip setpoints initially determined by Required Action A.3 may be affected by subsequent determinations of $F_Q(Z)$ and would require reductions for the Overpower ΔT setpoints within 72 hours of the $F_Q(Z)$ determination, if necessary, to comply with the decreased maximum allowable power level. Decreases in the $F_Q(Z)$ would allow increasing the Overpower ΔT trip setpoints.

A.4

Verification that $F_Q(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels are consistent with safety analyses assumptions.

(continued)

ACTIONS (continued)

B.1.

If Required Actions A.1 through A.3 are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 is modified by a Note. The Note applies during the first power ascension after a refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. This allowance is modified, however, by one of the Frequency conditions that requires verification that $F_Q(Z)$ is within specified limits after a power rise of more than 10% RTP over the THERMAL POWER at which it was last verified to be within specified limits. Because $F_Q(Z)$ could not have previously been measured in this reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q(Z)$ is made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q(Z)$ following a power increase of more than 10%, ensures that it was verified as soon as RTP (or any other level for extended operation) is achieved. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q(Z)$. The Frequency condition is not intended to require verification of these parameters after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which F_Q was last measured.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.1

Verification that $F_Q(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F_Q(Z) = F_Q^M(Z)$ 1.0815 (Ref. 4). $F_Q(Z)$ is then compared to its specified limits.

The limit with which $F_Q(Z)$ is compared varies inversely with power above 50% RTP and directly with a function called K(Z) provided in the COLR.

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q(Z)$ limit is met when RTP is achieved, because the highest peaking factors (i.e., the ratio of local power density to the core average power density) generally decrease as core average power level is increased.

If THERMAL POWER has been increased by ≥ 10% RTP since the last determination of $F_Q(Z)$, another evaluation of this factor is required 12 hours after achieving equilibrium conditions at this higher power level (to ensure that $F_Q(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

The Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup because such changes are slow and well controlled when the plant is operated in accordance with the Technical Specifications (TS).

REFERENCES

1. 10 CFR 50.46, 1974.
2. FSAR 14.2.6.
3. 10 CFR 50, Appendix A.
4. WCAP-7308-L-P-A, "Evaluation of Nuclear Hot Channel Factor Uncertainties".

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and the accident analysis assumptions remain valid. The design limits on local (pellet) and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during either normal operation or a postulated accident analyzed in the safety analyses.

$F^N_{\Delta H}$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F^N_{\Delta H}$ is a measure of the maximum total power produced in a fuel rod.

$F^N_{\Delta H}$ is sensitive to fuel loading patterns, bank insertion, and fuel burnup. $F^N_{\Delta H}$ typically increases with control bank insertion and typically decreases with fuel burnup.

$F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution map obtained with the movable incore detector system. Specifically, the results of the three dimensional power distribution map are analyzed by a computer to determine $F^N_{\Delta H}$. This factor is calculated at least every 31 EFPD. However, during power operation, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which address directly and continuously measured process variables.

The COLR provides peaking factor limits that ensure that the design basis value of the departure from nucleate boiling (DNB) is met for normal operation, operational transients, and any transient condition arising from events of moderate frequency.

(continued)

BASES

BACKGROUND (continued)

The DNB design basis precludes DNB and is met by limiting the minimum local DNB heat flux ratio to 1.3 using the W3 CHF correlation. All DNB limited transient events are assumed to begin with an $F^N_{\Delta H}$ value that satisfies the LCO requirements. Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is no overheating of the fuel that results in possible cladding perforation with the release of fission products to the reactor coolant.

APPLICABLE SAFETY ANALYSES

Limits on $F^N_{\Delta H}$ preclude core power distributions that exceed the following fuel design limits:

a. There must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition;

b. During a large break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200EF;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 225 calories/gram for non-irradiated fuel and 200 calories/gram for irradiated fuel (Ref. 1); and

d. Fuel design limits required by GDC 26 (Ref. 2) for the condition when control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

For transients that may be DNB limited, the Reactor Coolant System flow and $F^N_{\Delta H}$ are the core parameters of most importance. The limits on $F^N_{\Delta H}$ ensure that the DNB design basis is met for normal operation, operational transients, and any transients arising from events of moderate frequency. The DNB design basis is met by limiting the minimum DNBR to the 95/95 DNB criterion of applicable DNB correlation. This value provides a high degree of assurance that the hottest fuel rod in the core does not experience a DNB.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

The LOCA safety analysis indirectly models $F^N_{\Delta H}$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor (FQ(Z)) and the axial peaking factors are inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3).

The fuel is protected in part by Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid. The following LCOs ensure this: LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)," and LCO 3.2.1, "Heat Flux Hot Channel Factor (FQ(Z))."

$F^N_{\Delta H}$ and FQ(Z) are measured periodically using the movable incore detector system. Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of 10 CFR 50.36.

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least additional heat removal capability and thus the highest probability for a DNB.

(continued)

BASES

LCO (continued)

The limiting value of $F^N_{\Delta H}$, described by the equation contained in the COLR, is the design radial peaking factor used in the unit safety analyses.

A power multiplication factor in this equation includes an additional margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase a small amount for every 1% RTP reduction in THERMAL POWER as specified in the COLR.

APPLICABILITY

The $F^N_{\Delta H}$ limits must be maintained in MODE 1 to preclude core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other modes is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in other modes (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

ACTIONS

A.1.1

With $F^N_{\Delta H}$ exceeding its limit, the unit is allowed 4 hours to restore $F^N_{\Delta H}$ to within its limits. This restoration may, for example, involve realigning any misaligned rods or reducing power enough to bring $F^N_{\Delta H}$ within its power dependent limit. When the $F^N_{\Delta H}$ limit is exceeded, the DNBR limit is not likely violated in steady state operation, because events that could significantly perturb the $F^N_{\Delta H}$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limit may be violated if a DNB limiting event occurs. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore $F^N_{\Delta H}$ to within its limits without allowing the plant to remain in an unacceptable condition for an extended period of time.

Condition A is modified by a Note that requires that Required Actions A.2 and A.3 must be completed whenever Condition A is entered.

(continued)

BASES

ACTIONS

A.1.1 (continued)

Thus, if power is not reduced because this Required Action is completed within the 4 hour time period, Required Action A.2 nevertheless requires another measurement and calculation of $F^N_{\Delta H}$ within 24 hours in accordance with SR 3.2.2.1.

However, if power is reduced below 50% RTP, Required Action A.3 requires that another determination of $F^N_{\Delta H}$ must be done prior to exceeding 50% RTP, prior to exceeding 75% RTP, and within 24 hours after reaching or exceeding 95% RTP. In addition, Required Action A.2 is performed if power ascension is delayed past 24 hours.

A.1.2.1 and A.1.2.2

If the value of $F^N_{\Delta H}$ is not restored to within its specified limit either by adjusting a misaligned rod or by reducing THERMAL POWER, the alternative option is to reduce THERMAL POWER to < 50% RTP in accordance with Required Action A.1.2.1 and reduce the Power Range Neutron Flux — High to # 55% RTP in accordance with Required Action A.1.2.2. Reducing THERMAL POWER to < 50% RTP increases the DNB margin and does not likely cause the DNBR limit to be violated in steady state operation. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The allowed Completion Time of 4 hours for Required Action A.1.2.1 is consistent with those allowed for in Required Action A.1.1 and provides an acceptable time to reach the required power level from full power operation without allowing the plant to remain in an unacceptable condition for an extended period of time. The Completion Times of 4 hours for Required Actions A.1.1 and A.1.2.1 are not additive.

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.1.2.2 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

(continued)

BASES

ACTIONS (continued)

A.2

Once the power level has been reduced to < 50% RTP per Required Action A.1.2.1, an incore flux map (SR 3.2.2.1) must be obtained and the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by either Action A.1.1 or Action A.1.2.1. The Completion Time of 24 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 24 hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the incore flux map, perform the required calculations, and evaluate $F^N_{\Delta H}$.

A.3

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is $ 95% RTP.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action.

B.1

When Required Actions A.1.1 through A.3 cannot be completed within their required Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience regarding the time required to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The value of $F^N_{\Delta H}$ is determined by using the movable incore detector system to obtain a flux distribution map. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the measured flux distributions. The measured value of $F^N_{\Delta H}$ must be multiplied by 1.04 (75% available thimbles) to account for measurement uncertainty before making comparisons to the $F^N_{\Delta H}$ limit.

After each refueling, $F^N_{\Delta H}$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F^N_{\Delta H}$ limits are met at the beginning of each fuel cycle.

The 31 EFPD Frequency is acceptable because the power distribution changes relatively slowly over this amount of fuel burnup. Accordingly, this Frequency is short enough that the $F^N_{\Delta H}$ limit cannot be exceeded for any significant period of operation.

REFERENCES

1. FSAR 14.2.6.

2. 10 CFR 50, Appendix A.

3. 10 CFR 50.46.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD)
(Constant Axial Offset Control (CAOC) Methodology)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

The operating scheme used to control the axial power distribution, CAOC, involves maintaining the AFD within a tolerance band around a burnup dependent target, known as the target flux difference, to minimize the variation of the axial peaking factor and axial xenon distribution during unit maneuvers.

The target flux difference is determined at equilibrium xenon conditions. The control banks must be positioned within the core in accordance with their insertion limits and Control Bank D should be inserted near its normal position (i.e., ≥ 190 steps withdrawn) for steady state operation at high power levels. The power level should be as near RTP as practical. The value of the target flux difference obtained under these conditions divided by the Fraction of RTP is the target flux difference at RTP for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RTP value by the appropriate fractional THERMAL POWER level.

Periodic updating of the target flux difference value is necessary to follow the change of the flux difference at steady state conditions with burnup.

The Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$) and QPTR LCOs limit the radial component of the peaking factors.

(continued)

BASES

BACKGROUND (continued)

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator, through either the manual operation of the control banks, or automatic motion of control banks responding to temperature deviations resulting from either manual operation of the Chemical and Volume Control System to change boron concentration, or from power level changes.

APPLICABLE SAFETY ANALYSES

The AFD is a measure of axial power distribution skewing to the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution and, to a lesser extent, reactor coolant temperature and boron concentrations. The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

The CAOC methodology entails:

a. Establishing an envelope of allowed power shapes and power densities;

b. Devising an operating strategy for the cycle that maximizes unit flexibility (maneuvering) and minimizes axial power shape changes;

c. Demonstrating that this strategy does not result in core conditions that violate the envelope of permissible core power characteristics; and

d. Demonstrating that this power distribution control scheme can be effectively supervised with excore detectors.

The limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limits on the AFD also limit the range of power distributions that are assumed as initial conditions in analyzing Condition 2, 3, and 4 events. This ensures that fuel cladding integrity is maintained for these postulated accidents. The most important Condition 4 event is the loss of coolant accident. The most significant Condition 3 event is the loss of flow accident. The most significant Condition 2 events are uncontrolled bank withdrawal and boration or dilution accidents. Condition 2 accidents, assumed to begin from within the AFD limits, are used to confirm the adequacy of Overpower ΔT and Overtemperature ΔT trip setpoints.

The limits on the AFD satisfy Criterion 2 of 10 CFR 50.36.

LCO

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 1). Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom excore detector in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as $\%\Delta$ flux or $\%\Delta I$.

The AFD LCO establishes the limits for how much and for how long the measured AFD may deviate from a predetermined (i.e., target) AFD. The amount that the measured AFD may deviate from the target AFD is called the “target band” which is specified in the COLR. If the measured AFD is within the “target band,” then there are no restrictions on plant operations.

If the measured AFD cannot be consistently maintained within the “target band” but can be maintained within the “acceptable operation limits,” then reactor power must be reduced to < 90% RTP. However, even with power reduced, the measured AFD must be maintained within the target band for 23 out of every 24 hours (i.e., the cumulative penalty deviation time cannot be exceeded); otherwise additional power reductions are required.

(continued)

BASES

LCO (continued)

If the measured axial flux difference cannot be maintained within the "acceptable operation limits" or the cumulative penalty deviation time for operating outside the target band is exceeded, then reactor power must be reduced to < 50% RTP. There are no restrictions on measured AFD when reactor power is < 50% RTP; however, the measured AFD must be within the "target band" for a specified period of time (i.e., the cumulative penalty deviation time must be within a specified limit) before reactor power can be increased ≥ 50% RTP.

The required target band varies with axial burnup distribution, which in turn varies with the core average accumulated burnup. The target band defined in the COLR may provide one target band for the entire cycle or more than one band, each to be followed for a specific range of cycle burnup.

With THERMAL POWER ≥ 90% RTP, the AFD must be kept within the target band. With the AFD outside the target band with THERMAL POWER ≥ 90% RTP, the assumptions of the accident analyses may be violated.

The frequency of monitoring the AFD by the unit computer is once per minute providing an essentially continuous accumulation of penalty deviation time that allows the operator to accurately assess the status of the penalty deviation time.

Violating the LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its limits.

Target band and AFD acceptable operation limits are specified in the COLR.

The LCO is modified by four Notes. Note 1 states the conditions necessary for declaring the AFD outside of the target band. Notes 2 and 3 describe how the cumulative penalty deviation time is calculated. It is intended that the unit is operated with the AFD within the target band about the target flux difference. However, during rapid THERMAL POWER reductions, control bank motion may cause the AFD to deviate outside of the target band at reduced THERMAL POWER levels.

(continued)

BASES

LCO (continued)

This deviation does not affect the xenon distribution sufficiently to change the envelope of peaking factors that may be reached on a subsequent return to RTP with the AFD within the target band, provided the time duration of the deviation is limited. Accordingly, while THERMAL POWER is ≥ 50% RTP and < 90% RTP (i.e., Part b of this LCO), a 1 hour cumulative penalty deviation time limit, cumulative during the preceding 24 hours, is allowed during which the unit may be operated outside of the target band but within the acceptable operation limits provided in the COLR (Note 2). This penalty time is accumulated at the rate of 1 minute for each 1 minute of operating time within the power range of Part b of this LCO (i.e., THERMAL POWER ≥ 50% RTP). The cumulative penalty time is the sum of penalty times from Parts b and c of this LCO.

For THERMAL POWER levels > 15% RTP and < 50% RTP (i.e., Part c of this LCO), deviations of the AFD outside of the target band are less significant. Note 3 allows the accumulation of ½ minute penalty deviation time per 1 minute of actual time outside the target band and reflects this reduced significance. With THERMAL POWER < 15% RTP, AFD is not a significant parameter in the assumptions used in the safety analysis and, therefore, requires no limits. Because the xenon distribution produced at THERMAL POWER levels less than RTP does affect the power distribution as power is increased, unanalyzed xenon and power distribution is prevented by limiting the accumulated penalty deviation time.

For surveillance of the power range channels performed according to SR 3.3.1.6, Note 4 allows deviation outside the target band for 16 hours and no penalty deviation time is accumulated. Some deviation in the AFD is required for doing the NIS calibration with the incore detector system.

APPLICABILITY

AFD requirements are applicable in MODE 1 above 15% RTP. Above 50% RTP, the combination of THERMAL POWER and core peaking factors are the core parameters of primary importance in safety analyses (Ref. 1).

(continued)

BASES

APPLICABILITY (continued)

Between 15% RTP and 90% RTP, this LCO is applicable to ensure that the distributions of xenon are consistent with safety analysis assumptions.

At or below 15% RTP and for lower operating MODES, the stored energy in the fuel and the energy being transferred to the reactor coolant are low. The value of the AFD in these conditions does not affect the consequences of the design basis events.

Low signal levels in the excore channels may preclude obtaining valid AFD signals below 15% RTP.

ACTIONS

A.1

With the AFD outside the target band and THERMAL POWER ≥ 90% RTP, the assumptions used in the accident analyses may be violated with respect to the maximum heat generation. Therefore, a Completion Time of 15 minutes is allowed to restore the AFD to within the target band because xenon distributions change little in this relatively short time.

B.1

If the AFD cannot be restored within the target band, then reducing THERMAL POWER to < 90% RTP places the core in a condition that has been analyzed and found to be acceptable, provided that the AFD is within the acceptable operation limits provided in the COLR.

The allowed Completion Time of 15 minutes provides an acceptable time to reduce power to < 90% RTP without allowing the plant to remain in an unanalyzed condition for an extended period of time.

C.1

With THERMAL POWER < 90% RTP but ≥ 50% RTP, operation with the AFD outside the target band is allowed for up to 1 hour if the AFD is within the acceptable operation limits provided in the COLR.

(continued)

BASES

ACTIONS

C.1 (continued)

With the AFD within these limits, the resulting axial power distribution is acceptable as an initial condition for accident analyses assuming the then existing xenon distributions. The 1 hour cumulative penalty deviation time restricts the extent of xenon redistribution. Without this limitation, unanalyzed xenon axial distributions may result from a different pattern of xenon buildup and decay. The reduction to a power level < 50% RTP puts the reactor at a THERMAL POWER level at which the AFD is not a significant accident analysis parameter.

If the indicated AFD is outside the target band and outside the acceptable operation limits provided in the COLR, the peaking factors assumed in accident analysis may be exceeded with the existing xenon condition. (Any AFD within the target band is acceptable regardless of its relationship to the acceptable operation limits.) The Completion Time of 30 minutes allows for a prompt, yet orderly, reduction in power.

Condition C is modified by a Note that requires that Required Action C.1 must be completed whenever this Condition is entered.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

The AFD is monitored on an automatic basis using the unit process computer that has an AFD monitor alarm. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm if the AFDs for two or more OPERABLE excore channels are outside the target band and the THERMAL POWER is > 90% RTP. During operation at THERMAL POWER levels < 90% RTP but > 15% RTP, the computer provides an alarm when the cumulative penalty deviation time is > 1 hour in the previous 24 hours.

This Surveillance verifies that the AFD as indicated by the NIS excore channels is within the target band and consistent with the status of the AFD monitor alarm.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1 (continued)

The Surveillance Frequency of 7 days is adequate because the AFD is controlled by the operator and monitored by the process computer. Furthermore, any deviations of the AFD from the target band that is not alarmed should be readily noticed.

SR 3.2.3.2

With the AFD monitor alarm inoperable, the AFD is monitored to detect operation outside of the target band and to compute the penalty deviation time. During operation at ≥ 90% RTP, the AFD is monitored at a Surveillance Frequency of 15 minutes to ensure that the AFD is within its limits at high THERMAL POWER levels. At power levels < 90% RTP, but > 15% RTP, the Surveillance Frequency is reduced to 1 hour because the AFD may deviate from the target band for up to 1 hour using the methodology of Parts B and C of this LCO to calculate the cumulative penalty deviation time before corrective action is required.

SR 3.2.3.2 is modified by a Note that states that monitored and logged values of the AFD are assumed to exist for the preceding 24 hour interval in order for the operator to compute the cumulative penalty deviation time. The AFD should be monitored more frequently in periods of operation for which the power level or control bank positions are changing to allow corrective measures when the AFD is more likely to move outside the target band.

SR 3.2.3.3

This Surveillance requires that the target flux difference is updated at a Frequency of 31 effective full power days (EFPD) to account for small changes that may occur in the target flux differences in that period due to burnup by performing SR 3.2.3.4. Alternatively, linear interpolation between the most recent measurement of the target flux differences and a predicted end of cycle value provides a reasonable update.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.3.4

Measurement of the target flux difference is accomplished by taking a flux map when the core is at equilibrium xenon conditions, preferably at high power levels with the control banks nearly withdrawn. This flux map provides the equilibrium xenon axial power distribution from which the target value can be determined. The target flux difference varies slowly with core burnup.

A Frequency of 31 EFPD after each refueling and 92 EFPD thereafter for remeasuring the target flux differences adjusts the target flux difference for each excore channel to the value measured at steady state conditions. This is the basis for the CAOC. Remeasurement at this Surveillance interval also establishes the AFD target flux difference values that account for changes in incore excore calibrations that may have occurred in the interim.

A Note modifies this SR to allow the predicted end of cycle AFD from the cycle nuclear design to be used to determine the initial target flux difference after each refueling.

REFERENCES

1. FSAR, Chapter 7.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1.6, "Control Bank Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident, the peak cladding temperature must not exceed 2200°F (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition (Ref. 2);

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 225 calories/gram for non-irradiated fuel and 200 calories/gram for irradiated fuel (Ref. 3); and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 4).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and control bank insertion are established to preclude core power distributions that exceed the safety analyses limits.

The QPTR limits ensure that $F^N_{\Delta H}$ and $F_Q(Z)$ remain below their limiting values by preventing an undetected change in the gross radial power distribution.

In MODE 1, the $F^N_{\Delta H}$ and $F_Q(Z)$ limits must be maintained to preclude core power distributions from exceeding design limits assumed in the safety analyses.

The QPTR satisfies Criterion 2 of 10 CFR 50.36.

LCO

The QPTR limit of 1.02, at which corrective action is required, provides a margin of protection for both the DNB ratio and linear heat generation rate contributing to excessive power peaks resulting from X-Y plane power tilts. A limiting QPTR of 1.02 can be tolerated before the margin for uncertainty in $F_Q(Z)$ and ($F^N_{\Delta H}$) is possibly challenged.

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP to prevent core power distributions from exceeding the design limits.

Applicability in MODE 1 ≤ 50% RTP and in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F^N_{\Delta H}$ and $F_Q(Z)$ LCOs still apply, but allow progressively higher peaking factors at 50% RTP or lower.

(continued)

BASES (continued)

ACTIONS

A.1

With the QPTR exceeding its limit, a power level reduction of 3% RTP for each 1% by which the QPTR exceeds 1.00 is a conservative tradeoff of total core power with peak linear power. The Completion Time of 2 hours allows sufficient time to identify the cause and correct the tilt. Note that the power reduction itself may cause a change in the tilted condition. The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of QPTR. Increases in QPTR would require power reduction within 2 hours of the QPTR determination, if necessary, to comply with the decreases in maximum allowable power level. Decreases in QPTR would allow increasing the maximum allowable power level and increasing power up to this revised limit.

A.2

After completion of Required Action A.1, the QPTR may still exceed the specified limit. As such, any additional changes in the QPTR are detected by requiring a check of the QPTR once per 12 hours thereafter. A 12 hour Completion Time is sufficient because any additional change in QPTR would be relatively slow.

A.3

The peaking factors $F^N_{\Delta H}$ and $F_Q(Z)$ are of primary importance in ensuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing SRs on $F^N_{\Delta H}$ and $F_Q(Z)$ within the Completion Time of 24 hours after achieving equilibrium conditions from a Thermal Power reduction per Required Action A.1 ensures that these primary indicators of power distribution are within their respective limits. Equilibrium conditions are achieved when the core is sufficiently stable at intended operating conditions to support flux mapping. A Completion Time of 24 hours after achieving equilibrium conditions from a Thermal Power reduction per Required Action A.1 takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform a flux map.

(continued)

BASES

ACTIONS

A.3 (continued)

If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F^N_{\Delta H}$ and $F_Q(Z)$ with changes in power distribution. Relatively small changes are expected due to either burnup and xenon redistribution or correction of the cause for exceeding the QPTR limit.

A.4

Although $F^N_{\Delta H}$ and $F_Q(Z)$ are of primary importance as initial conditions in the safety analyses, other changes in the power distribution may occur as the QPTR limit is exceeded and may have an impact on the validity of the safety analysis. A change in the power distribution can affect such reactor parameters as bank worths and peaking factors for rod malfunction accidents. When the QPTR exceeds its limit, it does not necessarily mean a safety concern exists. It does mean that there is an indication of a change in the gross radial power distribution that requires an investigation and evaluation that is accomplished by examining the incore power distribution. Specifically, the core peaking factors and the quadrant tilt must be evaluated because they are the factors that best characterize the core power distribution. This re-evaluation is required to ensure that, before increasing THERMAL POWER to above the limit of Required Action A.1, the reactor core conditions are consistent with the assumptions in the safety analyses.

A.5

If the QPTR has exceeded the 1.02 limit and a re-evaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are normalized to restore QPTR to within limits prior to increasing THERMAL POWER to above the limit of Required Action A.1. Normalization is accomplished in such a manner that the indicated QPTR following normalization is near 1.00. This is done to detect any subsequent significant changes in QPTR.

(continued)

BASES

ACTIONS

A.5 (continued)

Required Action A.5 is modified by two Notes. Note 1 states that the QPT is not restored to within limits until after the re-evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). Note 2 states that if Required Action A.5 is performed, then Required Action A.6 shall be performed. Required Action A.5 normalizes the excore detectors to restore QPTR to within limits, which restores compliance with LCO 3.2.4. Thus, Note 2 prevents exiting the Actions prior to completing flux mapping to verify peaking factors, per Required Action A.6. These Notes are intended to prevent any ambiguity about the required sequence of actions.

A.6

Once the flux tilt is restored to within limits (i.e., Required Action A.5 is performed), it is acceptable to return to full power operation. However, as an added check that the core power distribution is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$ and $F^N_{\Delta H}$ are within their specified limits within 24 hours of achieving equilibrium conditions at RTP. As an added precaution, if the core power does not reach equilibrium conditions at RTP within 24 hours, but is increased slowly, then the peaking factor surveillances must be performed within 48 hours after increasing THERMAL POWER above the limit of Required Action A.1. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the limit of Required Action A.1, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

Required Action A.6 is modified by a Note that states that the peaking factor surveillances may only be done after the excore detectors have been normalized to restore QPTR to within limits (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are normalized to restore QPTR to within limits and the core returned to power.

(continued)

BASES

ACTIONS (continued)

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the unit must be brought to a MODE or condition in which the requirements do not apply. To achieve this status, THERMAL POWER must be reduced to < 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

SR 3.2.4.1 is modified by two Notes. Note 1 allows QPTR to be calculated with three power range channels if THERMAL POWER is ≤ 75% RTP and the input from one Power Range Neutron Flux channel is inoperable. Note 2 allows performance of SR 3.2.4.2 in lieu of SR 3.2.4.1.

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels, is within its limits. The Frequency of 7 days takes into account other indications and alarms available to the operator in the control room. For those causes of QPT that occur quickly (e.g., a dropped rod), there typically are other indications of abnormality that prompt a verification of core power tilt.

SR 3.2.4.2

This Surveillance is modified by a Note, which states that it is not required until 24 hours after the input from one or more Power Range Neutron Flux channels are inoperable and the THERMAL POWER is > 75% RTP.

With an NIS power range channel inoperable, tilt monitoring for a portion of the reactor core becomes degraded.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.4.2 (continued)

Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. Performing SR 3.2.4.2 at a Frequency of 24 hours provides an accurate alternative means for ensuring that any tilt remains within its limits.

For purposes of monitoring the QPTR when one power range channel is inoperable, the moveable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR and any previous data indicating a tilt. The incore detector monitoring is performed with a full incore flux map or two sets of four thimble locations with quarter core symmetry. The two sets of four symmetric thimbles is a set of eight unique detector locations.

The symmetric thimble flux map can be used to measure symmetric thimble "tilt." This can be compared to a reference symmetric thimble tilt, from the most recent full core flux map, to generate an incore QPTR. Therefore, incore monitoring of QPTR can be used to confirm that QPTR is within limits.

With one NIS channel inoperable, the indicated tilt may be changed from the value indicated with all four channels OPERABLE. To confirm that no change in tilt has actually occurred, which might cause the QPTR limit to be exceeded, the incore result may be compared against previous flux maps either using the symmetric thimbles as described above or a complete flux map.

REFERENCES

1. 10 CFR 50.46.

2. FSAR Section 14.1.6.

3. FSAR Section 14.2.6.

4. FSAR Section 3.1.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as specifying LCOs on other reactor system parameters and equipment performance.

The LSSS, defined in this specification as the Allowable Value, in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs).

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling (DNB);

2. Fuel centerline melt shall not occur; and

3. The RCS pressure SL of 2735 psig shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 50 and 10 CFR 50.67 criteria during AOOs.

(continued)

BASES

BACKGROUND (continued)

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that offsite dose shall be maintained within an acceptable fraction of 10 CFR 50.67 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RPS instrumentation is segmented into four distinct but interconnected modules as described in FSAR, Chapter 7 (Ref. 1), and as identified below:

1. Field transmitters or process sensors: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured;

2. Signal Process Control and Protection System including Analog Protection System, Nuclear Instrumentation System (NIS), field contacts, and protection channels: provides signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications;

3. RPS automatic initiation relay logic, including input, logic, and output: initiates proper unit shutdown in accordance with the defined logic, which is based on the bistable outputs from the signal process control and protection system; and

4. Reactor trip switchgear, including reactor trip breakers (RTBs) and bypass breakers: provides the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

(continued)

BASES

BACKGROUND (continued)

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented Allowable Value.

Signal Process Control and Protection System

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established to ensure that actuation will occur within the limits assumed in the accident analyses (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the RPS relay logic. Channel separation is maintained up to and through the actuation logic. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the RPS relay logic, while others provide input to the RPS relay logic, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the RPS relay logic and a control function, four channels with a two-out-of-four logic

(continued)

BACKGROUND (continued)

are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-279-1968 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 1 and discussed later in these Technical Specification Bases.

Two logic channels are required to ensure no single random failure of a logic channel will disable the RPS. The logic channels are designed such that testing required while the reactor is at power may be accomplished without causing trip.

Trip Setpoints and Allowable Values

The following describes the relationship between the safety limit, analytical limit, allowable value and channel component calibration acceptance criteria:

a. A Safety Limit (SL) is a limit on the combination of THERMAL POWER, RCS highest loop average temperature, and RCS pressure needed to protect the integrity of physical barriers that guard against the uncontrolled release of radioactivity (i.e., fuel, fuel cladding, RCS pressure boundary and containment). The safety limits are identified in Technical Specification 2.0, Safety Limits (SLs).

b. An Analytical Limit (AL) is the trip actuation point used as an input to the accident analyses presented in FSAR, Chapter 14 (Ref. 3). Analytical limits are developed from event analyses models which consider parameters such as process delays, rod insertion times, reactivity changes, instrument response times, etc. An analytical limit for a trip actuation point is established at a point that will ensure that a Safety Limit (SL) is not exceeded.

(continued)

BACKGROUND (continued)

c. An Allowable Value (AV) is the limiting actuation point for the entire channel of a trip function that will ensure, within the required level of confidence, that sufficient allocation exists between this actual trip function actuation point and the analytical limit. The Allowable Value is more conservative than the Analytical Limit to account for instrument uncertainties that either are not present or are not measured during periodic testing. Channel uncertainties that either are not present or are not measured during periodic testing may include design basis accident temperature and radiation effects (Ref. 5) or process dependent effects. The channel allowable value for each RPS function is controlled by Technical Specifications and is listed in Table 3.3.1-1, Reactor Protection System Instrumentation.

d. Calibration acceptance criteria are established by plant administrative programs for the components of a channel (i.e., required sensor, alarm, interlock, display, and trip function). The calibration acceptance criteria are established to ensure, within the required level of confidence, that the Allowable Value for the entire channel will not be exceeded during the calibration interval.

A description of the methodology used to calculate the channel allowable values and calibration acceptance criteria is provided in References 6 and 8.

Setpoints in accordance with the Allowable Value ensure that SLs are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed).

Each channel of the relay logic protection system can be tested on line to verify that the signal or setpoint accuracy is within the specified allowance requirements of calculations performed in accordance with the methodology and assumptions of the current unit specific setpoint methodology process that is based on References 10, 11 and 12 that are based on analytical limits consistent with Reference 3. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal.

(continued)

BASES

BACKGROUND (continued)

The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section. The Allowable Values listed in Table 3.3.1-1 and the Trip Setpoints calculated to ensure that Allowable Values are not exceeded during the calibration interval are based on the methodology described in the current unit specific setpoint methodology process that is based on References 10, 11 and 12, which incorporates all of the known uncertainties applicable for each channel. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Relay Logic Protection System

Relay logic is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of relay logic, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide reactor trip and/or ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

The relay logic performs the decision logic for actuating a reactor trip or ESF actuation, generates the electrical output signal that will initiate the required trip or actuation, and provides the status, permissive, and annunciator output signals to the control room.

The bistable outputs from the signal processing equipment are sensed by the relay logic equipment and combined into logic matrices that represent combinations indicative of various unit upset and accident transients. If a required logic matrix combination is completed, the system will initiate a reactor trip or send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

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BASES

BACKGROUND (continued)

Reactor Trip Breakers

The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity. Each RTB is equipped with a bypass breaker to allow testing of the RTB while the unit is at power. During normal operation the output from the reactor protection system is a voltage signal that energizes the undervoltage coils in the RTBs and bypass breakers, if in use. When the required logic matrix combination is completed, the reactor protection system output voltage signal is removed, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs and bypass breakers are tripped open. This allows the shutdown rods and control rods to fall into the core. In addition to the de-energization of the undervoltage coils, each breaker is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal from the reactor protection system. Either the undervoltage coil or the shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

There are two reactor trip breakers in series so that opening either will interrupt power to the control rod drive mechanisms (CRDMs) and allow the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. Each reactor trip breaker has a parallel reactor trip bypass breaker that is normally open. This feature allows testing of the reactor trip breakers at power. A trip signal from RPS logic train A will trip reactor trip breaker A and reactor trip bypass breaker B; and, a trip signal from logic train B will trip reactor trip breaker B and reactor trip bypass breaker A. During normal operation, both reactor trip breakers are closed and both reactor trip bypass breakers are open. An interlock trips both reactor trip bypass breakers if an attempt is made to close a reactor trip bypass breaker when the other reactor trip bypass breaker is already closed.

A trip breaker train consists of both the reactor trip breaker and reactor trip bypass breaker associated with a single RPS logic train if the breaker is racked in, closed, and capable of supplying power

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BASES

BACKGROUND (continued)

to the CRD System. Thus, the train consists of the main breaker; or, the main breaker and bypass breaker associated with this same RPS logic train if both the breaker and bypass are racked in, closed, and capable of supplying power to the CRD System.

The RPS decision logic Functions are described in the functional diagrams included in Reference 2. In addition to the reactor protection and ESFAS trips, the various "permissive interlocks" that are associated with unit conditions are also described.

When any one RPS train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RPS functions to maintain the Safety Limits (SLs) during all Abnormal Operating Occurrences (AOOs) and mitigates the consequences of DBAs in all MODES in which the Rod Control system is capable of rod withdrawal and one or more rods not fully inserted.

Each of the analyzed accidents and transients can be detected by one or more RPS Functions. The accident analysis described in Reference 3 takes credit for most RPS trip Functions. RPS trip Functions not specifically credited in the accident analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis. These RPS trip Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as backups to RPS trip Functions that were credited in the accident analysis.

The LCO requires all instrumentation performing an RPS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO generally requires OPERABILITY of four or three channels in each instrumentation Function, two channels of Manual Reactor Trip, and two trains in each Automatic Trip Logic Function. Generally, four OPERABLE instrumentation channels in a two-out-of-four configuration are required when one RPS channel is also used as a control system input. Isolation amplifiers prevent a control system failure from affecting the protection system (Ref. 1). This configuration accounts for the possibility of the shared channel failing in such a manner that it creates a transient that requires RPS action. In this case, the RPS will still provide protection, even with random failure of one of the other three protection channels. Three OPERABLE instrumentation channels in a two-out-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for RPS trip and disable one RPS channel. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

Reactor Protection System Functions

The safety analyses and OPERABILITY requirements applicable to each RPS Function are discussed below:

1. Manual Reactor Trip

The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time by using either of two reactor trip push buttons in the control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. It is used by the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its Trip Setpoint.

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip push button. Each channel activates the reactor trip breaker

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

in both trains. Two independent channels are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

In MODE 1 or 2, manual initiation of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE if one or more shutdown rods or control rods are withdrawn or the Rod Control System is capable of withdrawing the shutdown rods or the control rods. In this condition, inadvertent control rod withdrawal is possible. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the Rod Control System is not capable of withdrawing the shutdown rods or control rods and if all rods are fully inserted. If the rods cannot be withdrawn from the core, or all of the rods are inserted there is no need to be able to trip the reactor. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

2. Power Range Neutron Flux

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS power range detectors provide input to the Rod Control System and Turbine Control System. Four channels of NIS are required because the actuation logic must be able to withstand an input failure to the control system which may then require the protection function actuation and a single failure in the other three channels providing the protection function actuation. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

a. Power Range Neutron Flux-High

The Power Range Neutron Flux — High trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion leading to DNB during power operations. These can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires all four of the Power Range Neutron Flux — High channels to be OPERABLE. These channels are considered OPERABLE during required Surveillance tests that require insertion of a test signal if the channel remains untripped and capable of tripping due to an increasing neutron flux signal. During MODE 2 Physics Tests, only 3 channels are required because the output from one detector is used for test instrumentation.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux — High trip must be OPERABLE. This Function will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the NIS power range detectors cannot detect neutron levels in this range. In these MODES, the Power Range Neutron Flux — High does not have to be OPERABLE because the reactor is shut down and reactivity excursions into the power range are extremely unlikely. Other RPS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Power Range Neutron Flux-High Allowable Value and Trip Setpoint are in accordance with Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975 (Ref. 8).

b. Power Range Neutron Flux-Low

The LCO requirement for the Power Range Neutron Flux — Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the Power Range Neutron Flux — Low channels to be OPERABLE. During MODE 2 Physics Tests, only 3 channels are required because the output from one detector is used for test instrumentation.

In MODE 1, below the Power Range Neutron Flux (P-10 setpoint), and in MODE 2, the Power Range Neutron Flux — Low trip must be OPERABLE. This Function may be manually blocked by the operator when two out of four power range channels are greater than approximately 10% RTP (P-10 setpoint). This Function is automatically unblocked when three out of four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux — High trip Function.

In MODE 3, 4, 5, or 6, the Power Range Neutron Flux — Low trip Function does not have to be OPERABLE because the reactor is shut down and the NIS power range detectors cannot detect neutron levels in this range. Other RPS

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

The Power Range Neutron Flux-Low Allowable Value and Trip Setpoint are in accordance with Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975 (Ref. 8).

3. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux — Low Setpoint trip Function. Therefore, only one of the two channels of Intermediate Range Neutron Flux is Required to be OPERABLE in the Applicable MODES. Either of the two channels can be used to satisfy this requirement. The NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS intermediate range detectors do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires one channel of Intermediate Range Neutron Flux to be OPERABLE. One OPERABLE channel is sufficient to provide redundant protection to the Power Range Neutron Flux — Low Setpoint trip Function.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA) because LCO 3.3.1, Function 2.b, Power Range Neutron Flux-Low, is used to bound the analysis for an uncontrolled control rod assembly withdrawal from a subcritical condition. The surveillance acceptance criterion used for this function is ≤ 28% RTP. This value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, (Ref. 8).

Because this trip Function is important only during startup, there is generally no need to disable channels for testing while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

The Intermediate Range Neutron Flux trip must be OPERABLE in MODE 1 below the P-10 setpoint, and in MODE 2 above the P-6 setpoint, when there is a potential for an uncontrolled RCCA bank rod withdrawal accident during reactor startup. Above the P-10 setpoint, the Power Range Neutron Flux — High Setpoint trip provides core protection for a rod withdrawal accident. In MODE 2, below the P-6 setpoint, the source Range Neutron Flux Trip provides backup core protection for reactivity accidents. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be fully inserted and only the shutdown rods may be withdrawn. The reactor cannot be started up in this condition. The core also has the required SDM to mitigate the consequences of a positive reactivity addition accident. In MODE 6, all rods are fully inserted and the core has a required increased SDM. Also, the NIS intermediate range detectors cannot detect neutron levels present in this MODE.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4. Source Range Neutron Flux

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux — Low trip Function. Therefore, only one of the two channels of Source Range Neutron Flux is required to be OPERABLE in the Applicable MODES. Either of the two channels can be used to satisfy this requirement. In MODES 3, 4, and 5, administrative controls also prevent the uncontrolled withdrawal of rods. The NIS source range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RPS automatic protection function required in MODES 3, 4, and 5 when rods are capable of withdrawal or one or more rods are not fully inserted.

The LCO requires one channel of Source Range Neutron Flux to be OPERABLE. One OPERABLE channel is sufficient to provide redundant protection to the Power Range Neutron Flux — Low Setpoint trip Function.

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA) because LCO 3.3.1, Function 2.b, Power Range Neutron Flux-Low, is used to bound the analysis for an uncontrolled control rod assembly withdrawal from a subcritical condition. The surveillance acceptance criterion used for this function is ≤6.0 E+5 counts per second.

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical. The Function also provides visual neutron flux indication in the control room.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 2 when below the P-6 setpoint and in MODES 3, 4, and 5, when there is a potential for an uncontrolled RCCA bank withdrawal accident, the Source Range Neutron Flux trip must be OPERABLE. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux — Low trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS source range detectors are de-energized.

In MODEs 3, 4, and 5 with all rods fully inserted and the Rod Control System not capable of rod withdrawal, and in MODE 6, the outputs of this function to the RPS logic are not required to be OPERABLE. The requirements for the NIS source range detectors in MODE 6 are addressed in LCO 3.9.2, "Nuclear Instrumentation."

5. Overtemperature ΔT

The Overtemperature ΔT trip Function is provided to ensure that the design limit DNBR is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system.
The Overtemperature ΔT trip Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature — the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;

- pressurizer pressure — the Trip Setpoint is varied to correct for changes in system pressure; and

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- axial power distribution — f(ΔI), the Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the Technical Specification limit, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

Dynamic compensation is included for system piping delays from the core to the temperature measurement system.

The Overtemperature ΔT trip Function is calculated for each loop as described in Note 1 of Table 3.3.1-1. Trip occurs if Overtemperature ΔT is indicated in two loops. The pressure and temperature signals are used for other control functions. Therefore, the actuation logic is designed to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation.

The LCO requires all four channels of the Overtemperature ΔT trip Function to be OPERABLE. Note that the Overtemperature ΔT Function receives input from channels shared with other RPS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

6. <u>Overpower ΔT</u>

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the required range of the Overtemperature ΔT trip Function and provides a backup to the Power Range Neutron Flux — High Setpoint trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature — the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature; and
- rate of change of reactor coolant average temperature — including a constant determined by dynamic considerations that provides compensation for the delays between the core and the temperature measurement system.

The Overpower ΔT trip Function is calculated for each loop as per Note 2 of Table 3.3.1-1. Trip occurs if Overpower ΔT is indicated in two loops. The temperature signals are used for other control functions. Therefore, the actuation logic is designed to withstand an input failure to the control system, which may then require the protection function actuation and a single failure in the remaining channels providing the protection function actuation.

The LCO requires four channels of the Overpower ΔT trip Function to be OPERABLE. Note that the Overpower ΔT trip Function receives input from channels shared with other RPS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4,

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

7. Pressurizer Pressure

The same sensors provide input to the Pressurizer Pressure — High and — Low trips and the Overtemperature ΔT trip. The Pressurizer Pressure channels are also used to provide input to the Pressurizer Pressure Control System. Therefore, the actuation logic is designed to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that the plant design and this LCO require 4 channels for the Pressurizer Pressure— Low trips but requires only 3 channels of Pressurizer Pressure — High. This difference recognizes the role of pressurizer code safety valves in response to a high pressure condition.

a. Pressurizer Pressure-Low

The Pressurizer Pressure — Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

The LCO requires four channels of Pressurizer Pressure — Low to be OPERABLE.

In MODE 1, when DNB is a major concern, the Pressurizer Pressure — Low trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (NIS power range P-10 or turbine first stage pressure greater than approximately 10% of full power equivalent). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, no conceivable power distributions can occur that would cause DNB concerns.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Pressurizer Pressure-High

The Pressurizer Pressure — High trip Function ensures that protection is provided against overpressurizing the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

The LCO requires three channels of the Pressurizer Pressure — High to be OPERABLE.

The Pressurizer Pressure — High Allowable Value is selected to be below the pressurizer safety valve actuation pressure and above the power operated relief valve (PORV) setting. This setting minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

In MODE 1 or 2, the Pressurizer Pressure — High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure — High trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when RCS temperature is less than the LTOP arming temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP).

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

8. Pressurizer Water Level-High

The Pressurizer Water Level — High trip Function provides a backup signal for the Pressurizer Pressure — High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The LCO requires three channels of Pressurizer Water Level — High to be OPERABLE. The pressurizer level channels are used as input to the Pressurizer Level Control System. A fourth channel is not required to address control/protection interaction concerns because the level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting. Therefore, with the slow rate of charging available, pressure overshoot due to level channel failure cannot cause the safety valve to lift before reactor high pressure trip.

In MODE 1, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level — High trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock.

On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

9. Reactor Coolant Flow-Low

a. Reactor Coolant Flow-Low (Single Loop)

The Reactor Coolant Flow — Low (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in loop flow. Above the P-8 setpoint, a loss of flow in any RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow — Low channels per RCS loop to be OPERABLE in MODE 1 above P-8. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core. In MODE 1 below the P-8 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip (Function 9.b) because of the lower power level and the greater margin to the design limit DNBR.

b. Reactor Coolant Flow-Low (Two Loops)

The Reactor Coolant Flow — Low (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in two or more RCS loops while avoiding reactor trips due to normal variations in loop flow.

Above the P-7 setpoint and below the P-8 setpoint, a loss of flow in two or more loops will initiate a reactor trip. Each loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires three Reactor Coolant Flow — Low channels per loop to be OPERABLE. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the Reactor Coolant Flow — Low (Two Loops) trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on low flow in two or more RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any one loop (Function 9.a) will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

10. Reactor Coolant Pump (RCP) Breaker Position

Both RCP Breaker Position trip Functions operate to anticipate the Reactor Coolant Flow — Low trips to avoid RCS heatup that would occur before the low flow trip actuates.

a. Reactor Coolant Pump Breaker Position (Single Loop)

The RCP Breaker Position (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in one RCS loop. The position of each RCP breaker is monitored. If one RCP breaker is open above the P-8 setpoint, a reactor trip is initiated. This trip Function will generate a reactor trip before the Reactor Coolant Flow — Low (Single Loop) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this trip Function because the RCS Flow — Low trip alone provides sufficient protection of unit SLs for loss of

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of a pump. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-8 setpoint, when a loss of flow in any RCS loop could result in DNB conditions in the core, the RCP Breaker Position (Single Loop) trip must be OPERABLE. In MODE 1 below the P-8 setpoint, a loss of flow in two or more loops (Function 10.b) is required to actuate a reactor trip because of the lower power level and the greater margin to the design limit DNBR.

b. <u>Reactor Coolant Pump Breaker Position (Two Loops)</u>

The RCP Breaker Position (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The position of each RCP breaker is monitored. Above the P-7 setpoint a loss of flow in two or more loops will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow — Low (Two Loops) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this Function because the RCS Flow — Low trip alone provides sufficient protection of unit SLs for loss of

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of an RCP. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the RCP Breaker Position (Two Loops) trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any one loop (Function 10.a) will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

11. <u>Undervoltage Reactor Coolant Pumps (6.9 kV Bus)</u>

The Undervoltage RCPs direct reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The voltage to each 6.9 kV bus used to power an RCP is monitored. Above the P-7 setpoint, a loss of voltage detected on two or more RCP buses will initiate a direct reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow — Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the Undervoltage RCPs channels associated with the direct reactor trip and are provided to prevent reactor trips due to momentary electrical power transients.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires one Undervoltage RCPs channel per bus to be OPERABLE. The Allowable Value for this trip function is shown as NA because there is no Analytical Limit for RCP Undervoltage. The RCPs will continue to operate and deliver required RCS flow during an Undervoltage Condition. The reactor trip on RCP Undervoltage is a time-zero initiating event assumed in the safety analysis (Reference 3). The UV relay is adjusted for a nominal trip setpoint of 75% of the 6900 Vac bus voltage and the surveillance acceptance criterion used for this function is ≥ 70%.

In MODE 1 above the P-7 setpoint, the Undervoltage RCP trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled.

12. Underfrequency Reactor Coolant Pumps

The Underfrequency RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops from a major network frequency disturbance. An underfrequency condition will slow down the pumps, thereby reducing their coastdown time following a pump trip. The proper coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is monitored. A loss of frequency detected on two or more RCP buses trips all four RCPs, a condition that will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow — Low (Two Loops) Trip Setpoint is reached.

The LCO requires one Underfrequency RCP channel per bus to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In Mode 1 above the P-7 Setpoint, the Underfrequency RCP's trip must be OPERABLE. Below the P-7 Setpoint, all reactor trips on loss off flow are automatically blocked since no conceivable power distribution could occur that would cause a DNB Concern at this low power level. Above the P-7 Setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled.

13. Steam Generator Water Level-Low Low

The SG Water Level — Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the AFW System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low low level in any SG is indicative of a loss of heat sink for the reactor. The "B" channel level transmitters provide input to the SG Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. This Function also performs the ESFAS function of starting the AFW pumps on low low SG level.

The LCO requires three channels of SG Water Level — Low Low per SG to be OPERABLE. Each SG is considered to be a separate function. Therefore, separate condition entry is allowed for each SG.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level — Low Low trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater (MFW) System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5,

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

or 6, the SG Water Level — Low Low Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not critical. Decay heat removal is accomplished by the AFW System in MODE 3 and 4 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

14. Steam Generator Water Level-Low, Coincident With Steam Flow/Feedwater Flow Mismatch

SG Water Level — Low, in conjunction with the Steam Flow/Feedwater Flow Mismatch, ensures that protection is provided against a loss of heat sink and actuates the AFW System. In addition to a decreasing water level in the SG, the difference between feedwater flow and steam flow is evaluated to determine if feedwater flow is significantly less than steam flow. With less feedwater flow than steam flow, SG level will decrease at a rate dependent upon the magnitude of the difference in flow rates. The required logic is developed from two SG level channels and two Steam Flow/Feedwater Flow Mismatch channels per SG. One narrow range level channel coincident with the associated Steam Flow/Feedwater Flow Mismatch channel for the same SG (steam flow greater than feed flow) will actuate a reactor trip.

The LCO requires two channels of SG Water Level — Low coincident with Steam Flow/Feedwater Flow Mismatch.

Each SG is considered to be a separate function. Therefore, separate condition entry is allowed for each SG.

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA) because LCO 3.3.1, Function 13, Steam Generator Water Level-Low Low, is used to bound the analysis for a loss of feedwater event. The allowable values required for OPERABILITY of Function 13 is ≥ 4.0%. The surveillance acceptance criteria used for Function 14 are ≥ 7.5% narrow range level and ≤ 1.33E+6 pounds per hour steam flow/feedwater flow mismatch.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level — Low coincident with Steam Flow/Feedwater Flow Mismatch trip must be OPERABLE. The normal source of water for the SGs is the MFW System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level — Low coincident with Steam Flow/Feedwater Flow Mismatch Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not critical. Decay heat removal is accomplished by the AFW System in MODE 3 and 4 and by the RHR System in MODE 4, 5, or 6. The MFW System is in operation only in MODE 1 or 2 and, therefore, this trip Function need only be OPERABLE in these MODES.

15. <u>Turbine Trip — Low Auto-Stop Oil Pressure</u>

The Turbine Trip — Low Auto-Stop Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-8 setpoint will not actuate a reactor trip. Three pressure switches monitor the control oil pressure in the Turbine Control System. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure — High trip Function and RCS integrity is ensured by the pressurizer safety valves.

The LCO requires three channels of Turbine Trip — Low Auto- Stop Oil Pressure to be OPERABLE in MODE 1 above P-8.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Below the P-8 setpoint, a turbine trip does not actuate a reactor trip. In MODE 1 (below P-8 setpoint), 2, 3, 4, 5, or 6, there is no potential for a turbine trip that would require a reactor trip, and the Turbine Trip — Low Auto-Stop Oil Pressure trip Function does not need to be OPERABLE.

16. Safety Injection Input from Engineered Safety Feature Actuation System

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RPS, the ESFAS automatic actuation logic will initiate a reactor trip signal upon any signal that initiates SI. This is a condition of acceptability for the LOCA. However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present.

Trip Setpoint and Allowable Values are not applicable to this Function. The SI Input is provided by relay in the ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

17. Reactor Trip System Interlocks

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current unit status. They back up operator actions to ensure protection system Functions are not bypassed during unit conditions under which the safety analysis assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE when the associated reactor trip functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. Manual defeat of the P-6 interlock can be accomplished at any time by simultaneous actuation of both Reset pushbuttons. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. The source range trip is blocked by removing the high voltage to the detectors;

- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux reactor trip; and

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip will be blocked, and this Function will no longer be necessary.

In MODE 3, 4, 5, or 6, the P-6 interlock does not have to be OPERABLE because the NIS Source Range is providing core protection if required.

The Allowable Value is NA for this function because there is no corresponding analytical limit modeled in the accident analysis. The surveillance acceptance criterion used for this Function is ≥ 3.1E-11 Amps.

b. Low Power Reactor Trips Block, P-7

The Low Power Reactor Trips Block, P-7 interlock, is actuated by input from either the Power Range Neutron Flux, P-10, or the Turbine First Stage Pressure. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

(1) on increasing power, the P-7 interlock (i.e., 2 of 4 Power Range channels increasing above the P-10 (Function 17.d) setpoint or 1 of 2 Turbine First Stage Pressure (Function 17.e) setpoint) automatically enables reactor trips on the following Functions:

- Pressurizer Pressure — Low;
- Pressurizer Water Level — High;
- Reactor Coolant Flow — Low (Two Loops);
- RCPs Breaker Open (Two Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These reactor trips are only required when operating above the P-7 setpoint (approximately 10% power). The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

(2) on decreasing power, the P-7 interlock (i.e., 3 of 4 Power Range channels decreasing below the P-10 (Function 17.d) setpoint and 2 of 2 Turbine First Stage Pressure channels decreasing below the Turbine First Stage Pressure (Function 17.e) setpoint) automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure — Low;
- Pressurizer Water Level — High;
- Reactor Coolant Flow — Low (Two Loops);
- RCP Breaker Position (Two Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs

An Allowable Value is not applicable to the P-7 interlock because it is a logic Function. The P-10 interlock (Function 17.d) governs input from the Power Range instruments and the Turbine First Stage Pressure interlock (Function 17.e) governs input for turbine power.

The P-7 interlock is a logic Function with train and not channel identity. Therefore, the LCO requires one channel per train (i.e., two trains) of Low Power Reactor Trips Block, P-7 interlock to be OPERABLE in MODE 1.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below 10% power, which is in MODE 1.

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated below 50% power as determined by NIS power range detectors. The P-8 interlock automatically enables the Reactor Coolant Flow — Low (Single Loop) and RCP Breaker Position (Single Loop) reactor trips on low flow in one or more RCS loops whenever at least 2 of 4 of the Power Range instruments increase to above the P-8 setpoint. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than approximately 50% power. On decreasing power, the reactor trip on low flow in any loop is automatically blocked whenever at least 3 of 4 the Power Range instruments decrease to below the P-8 setpoint.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

The Allowable Value is NA for this Function because there is no corresponding analytical limit modeled in the accident analysis. The surveillance acceptance criterion used for this Function is ≤ 35% RTP.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated at approximately 10% power, as determined by two-out-of-four NIS power range detectors. If power level falls below 10% RTP on 3 of 4 channels, the nuclear instrument trips will be automatically unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip;
- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux — Low reactor trip;
- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip by de-energizing the NIS source range detectors;
- the P-10 interlock provides one of the two inputs to the P-7 interlock; and
- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux — Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux — Low and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

The Allowable Value is NA for this Function because there is no corresponding analytical limit modeled in the accident analysis. The surveillance acceptance criterion used for this Function is ≤ 9% RTP.

e. Turbine First Stage Pressure

The Turbine First Stage Pressure interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the rated full power pressure. This is determined by one-out-of-two pressure detectors. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available.

The LCO requires two channels of Turbine Impulse Pressure, input to the P-7 interlock, to be OPERABLE in MODE 1.

The Turbine First Stage Pressure interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

The Allowable Value is NA for this Function because there is no corresponding analytical limit modeled in the accident analysis. The surveillance acceptance criterion used for this Function is ≤ 9.5% RTP.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

18. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of individual trip mechanisms. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RPS logic train that are racked in, closed, and capable of supplying power to the Rod Control System. Thus, the train may consist of the main breaker, bypass breaker, or main breaker and bypass breaker, depending upon the system configuration. Two OPERABLE trains ensure no single random failure can disable the RPS trip capability.

The LCO requires two OPERABLE trains of trip breakers. Two OPERABLE trains ensure no single random failure can disable the RPS trip capability. When a reactor trip breaker is being tested, both reactor trip breaker and the reactor trip bypass breaker associated with the RPS logic train not in test are closed. In this configuration, a single failure in the RPS logic train not in test could disable RPS trip capability; therefore, limits on the duration of testing are established.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the Rod Control System, or declared inoperable under Function 18 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

20. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 18 and 19) and Automatic Trip Logic (Function 20) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with a bypass breaker (RTBB) to allow testing of the trip breaker while the unit is at power. Each RTB and RTBB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. The reactor trip signals generated by the RPS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RPS Automatic Trip Logic to be OPERABLE. Having two OPERABLE channels ensures that random failure of a single logic channel will not prevent reactor trip.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

The RPS instrumentation satisfies Criterion 3 of 10 CFR 50.36.

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.1-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

(continued)

BASES

ACTIONS (continued)

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all RPS protection Functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1 and B.2

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the relay logic for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 additional hours (54 hours total time). The 6 additional hours to reach MODE 3 is reasonable, based on operating experience, to reach MODE 3 from full power operation in an orderly manner and without challenging unit systems. With the unit in MODE 3, ACTION C applies to any inoperable Manual Reactor Trip Function if the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

(continued)

ACTIONS (continued)

C.1 and C.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 when the Rod Control System capable of rod withdrawal or one or more rods are not fully inserted:

- Manual Reactor Trip;
- RTBs;
- RTB Undervoltage and Shunt Trip Mechanisms; and
- Automatic Trip Logic.

This action addresses the train orientation of the relay logic for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With rods fully inserted and the Rod Control System incapable of rod withdrawal, these Functions are no longer required.

The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

D.1 and D.2

Condition D applies to the Power Range Neutron Flux — High Function.

The NIS power range detectors provide input to the Rod Control System and, therefore, have a two-out-of-four trip logic. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

logic for actuation. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in WCAP-10271-P-A (Ref. 7).

The 6 hour Completion Time is consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Twelve hours are allowed to place the plant in MODE 3. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to 8 hours while performing routine surveillance testing of other channels. The Note also allows placing the inoperable channel in the bypass condition to allow setpoint adjustments of other channels when required to reduce the setpoint in accordance with other Technical Specifications.

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux — Low;
- Overtemperature ΔT;
- Overpower ΔT;
- Pressurizer Pressure — High;
- SG Water Level — Low Low; and
- SG Water Level — Low coincident with Steam Flow/Feedwater Flow Mismatch.

(continued)

ACTIONS

E.1 and E.2 (continued)

A known inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 7.

If the operable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 8 hours while performing routine surveillance testing of the other channels.

F.1 and F.2

Condition F applies when there are no Intermediate Range Neutron Flux trip channels OPERABLE in MODE 2 when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, one or both Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

(continued)

ACTIONS (continued)

G.1

Condition G applies when there are no Source Range Neutron Flux trip channels OPERABLE when in MODE 2, below the P-6 setpoint, and in MODE 3, 4, or 5 with the Rod Control capable of rod withdrawal or one or more rods not rods fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With both source range channels noperable, the RTBs must be opened immediately. With the RTB's open, the core is in a more stable condition.

H.1 and H.2

Condition H applies to the following reactor trip Functions:

- Pressurizer Pressure — Low;
- Pressurizer Water Level — High;
- Reactor Coolant Flow — Low;
- RCP Breaker Position (Two Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip above the P-7 setpoint for the two loop function and above the P-8 setpoint for the single loop function.

These Functions do not have to be OPERABLE below the P-7 setpoint because there are no loss of flow trips below the P-7 setpoint. The 6 hours allowed to place the channel in the tripped condition is justified in Reference 7. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot

(continued)

BASES

ACTIONS (continued)

H.1 and H.2 (continued)

be restored to OPERABLE status or placed in trip within the specified Completion Time. The Reactor Coolant Flow-Low (Single Loop) reactor trip does not have to be OPERABLE below the P-8 setpoint; however, the Required Action must take the plant below the P-7 setpoint if the inoperable channel is not tripped within 6 hour because of the shared components between this function and the Reactor Coolant Flow-Low (Two Loop) reactor trip function.

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition H.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 8 hours while performing routine surveillance testing of the other channels.

I.1 and I.2

Condition I applies to the RCP Breaker Position (Single Loop) reactor trip Function. There is one breaker position device per RCP breaker. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 6 hours. If the channel cannot be restored to OPERABLE status within the 6 hours, then THERMAL POWER must be reduced below the P-8 setpoint within the next 4 hours.

This places the unit in a MODE where the LCO is no longer applicable. This Function does not have to be OPERABLE below the P-8 setpoint because other RPS Functions provide core protection below the P-8 setpoint. The 6 hours allowed to restore the channel to OPERABLE status and the 4 additional hours allowed to reduce THERMAL POWER to below the P-8 setpoint are justified in Reference 7.

(continued)

BASES

ACTIONS

I.1 and I.2 (continued)

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 8 hours while performing routine surveillance testing of the other channels.

J.1 and J.2

Condition J applies to Turbine Trip on Low Auto-Stop Oil Pressure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 6 hours. If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-8 setpoint within the next 6 hours. The 6 hours allowed to place the inoperable channel in the tripped condition and the 10 hours allowed for reducing power are justified in Reference 7.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 8 hours while performing routine surveillance testing of the other channels.

K.1 and K.2

Condition K applies to the SI Input from ESFAS reactor trip and the RPS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RPS for these Functions. With one train inoperable, 6 hours are allowed to restore the train to OPERABLE status (Required Action K.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 6 hours (Required Action K.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The Completion Time of 6 hours (Required Action K.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows bypassing one train up to 8 hours for surveillance testing, provided the other train is OPERABLE.

(continued)

BASES

ACTIONS (continued)

L.1 and L.2

Condition L applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RPS for the RTBs. With one train inoperable, 1 hour is allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RPS Function. Placing the unit in MODE 3 results in ACTION C entry while RTB(s) are inoperable.

The Required Actions have been modified by two Notes. Note 1 allows one channel to be bypassed for up to 2 hours for surveillance testing, provided the other channel is OPERABLE. Note 2 allows one RTB to be bypassed for up to 2 hours for maintenance on undervoltage or shunt trip mechanisms if the other RTB train is OPERABLE. The 2 hour time limit is justified in Reference 7.

As noted in Reference 9, the allowance of 2 hours for test and maintenance of reactor trip breakers provided in Condition L, Note 1, is less than the 6 hour allowable out of service time and the 8 hour allowance for testing of RPS train A and train B. In practice, if the reactor trip breaker is being tested at the same time as the associated logic train, the 8 hour allowance for testing of RPS train A and train B applies to both the logic train and the reactor trip breaker. This is acceptable based on the Safety Evaluation Report for Reference 7.

M.1 and M.2

Condition M applies to the P-6 and P-10 interlocks. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 3 within the next 6 hours. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual

(continued)

BASES

ACTIONS

M.1 and M.2 (continued)

operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RPS Function.

N.1 and N.2

Condition N applies to the P-7 and P-8 interlocks and the turbine first stage pressure input to P-7. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 2 within the next 6 hours. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging unit systems.

O.1 and O.2

Condition O applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or the unit must be placed in a MODE where the requirement does not apply. This is accomplished by placing the unit in MODE 3 within the next 6 hours (54 hours total time). The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

With the unit in MODE 3, ACTION C applies to any inoperable RTB trip mechanism. The affected RTB shall not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance to one of the diverse features. The allowable time for performing maintenance of the diverse features is 2 hours for the reasons stated under Condition L.

(continued)

ACTIONS

O.1 and O.2 (continued)

The Completion Time of 48 hours for Required Action O.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

SURVEILLANCE REQUIREMENTS

The SRs for each RPS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RPS Functions.

Note that each channel of process protection supplies both train A and train B of the RPS. When testing an individual channel, the SR is not met until both train A and train B logic are tested. The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1 continued)

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the NIS channel output every 24 hours. If the calorimetric exceeds the NIS channel output by > 2% RTP, the NIS is not declared inoperable, but must be adjusted. If the NIS channel output cannot be properly adjusted, the channel is declared inoperable.

Two Notes modify SR 3.3.1.2. The first Note indicates that the NIS channel output shall be adjusted consistent with the calorimetric results if the absolute difference between the NIS channel output and the calorimetric is > 2% RTP. The second Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 15% RTP. At lower power levels, calorimetric data are inaccurate.

The Frequency of every 24 hours is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Together these factors demonstrate the change in the absolute difference between NIS and heat balance calculated powers rarely exceeds 2% in any 24 hour period.

In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output every 31 EFPD. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3 (continued)

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

Two Notes modify SR 3.3.1.3. Note 1 indicates that the excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%. SR 3.3.1.3 is performed to ensure that the AFD input to the Overtemperature Delta T and the system used to monitor LCO 3.2.3, AFD, are within acceptable limits. The limiting AFD is established to provide the required margin when operating at the highest power level. As power level decreases, the thermal limit becomes less sensitive to AFD because the overall margin to the thermal limit increases. Note 2 clarifies that the Surveillance is required only if reactor power is ≥ 90% because the requirements of LCO 3.2.3, Axial Flux Difference (AFD), are relaxed significantly below 90% RTP.

The Frequency of every 31 EFPD is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT every 31 days on a STAGGERED TEST BASIS. This test shall verify OPERABILITY by actuation of the end devices.

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Independent verification of RTB undervoltage and shunt trip Function is not required for the bypass breakers. No capability is provided for performing such a test at power. The independent test of the undervoltage and shunt trip function for bypass breakers is included in SR 3.3.1.14. The bypass

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.4 (continued)

breaker test shall include a local shunt trip. A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The RPS relay logic is tested every 31 days on a STAGGERED TEST BASIS. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. All possible logic combinations, with and without applicable permissives, are tested for each protection function required by Table 3.31-1. The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is > 90% because the requirements of LCO 3.2.3, Axial Flux Difference (AFD), are relaxed significantly below 90% RTP. SR 3.3.1.6 is performed to ensure that the AFD input to the Overtemperature Delta T and the system used to monitor LCO

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.6 (continued)

3.2.3 AFD are within acceptable limits. The limiting AFD is established to provide the required margin when operating at the highest power level. As power level decreases, the thermal limit becomes less sensitive to AFD because the overall margin to the thermal limit increases.

The Frequency of 92 EFPD is adequate based on operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 92 days.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function.

Setpoints must be within the Allowable Values specified in Table 3.3.1-1.

The "as found" and "as left" values must also be recorded and reviewed. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology process that is based on References 10, 11 and 12 which incorporates the requirements of Reference 7.

SR 3.3.1.7 is modified by a Note that provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for 4 hours in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3. The 4 hour deferral is needed because the testing required by SR 3.3.1.7 and SR

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

3.3.1.8 cannot be performed on the Source Range, Intermediate Range and Power Range Instruments until in the Applicable Mode and the proximity of these instruments prevents working on more than one instrument at any one time.

The Frequency of 92 days is justified in Reference 7.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, except it is modified by a Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit condition. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within 92 days of the Frequencies prior to reactor startup and 12 hours after reducing power below P-10 and 4 hours after reducing power below P-6.

The Frequency of "prior to startup" and the note on surveillance intervals ensures this surveillance is performed prior to critical operations or within the prior 92 days and applies to the source, intermediate and power range low instrument channels. The Frequency of "12 hours after reducing power below P-10" (applicable to intermediate and power range low channels) and "4 hours after reducing power below P-6" (applicable to source range channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance.

The Frequency of every 92 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup. Additionally, this SR must be completed for the intermediate and power range low channels within 12 hours after reducing power below the P-10 setpoint and must be completed for the source range low channel within 4 hours after reducing power below the P-6 setpoint. The MODE of Applicability for this

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 for more than 12 hours or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the time limit unless removed from the mode of applicability. The specified Frequency provides a reasonable time to complete the required testing or place the unit in a MODE where this surveillance is no longer required.

This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and within a reasonable time after reducing power into the applicable MODE (< P-10 or < P-6), based on startup testing or testing within the prior 92 days (e.g., during the shutdown). The deferral of the requirement to perform this test until 12 and 4 hours after entering the Applicable condition is needed because the testing required by SR 3.3.1.7 and SR 3.3.1.8 cannot be performed on the Source Range, Intermediate Range, and Power Range instruments until in the Applicable Mode and the proximity of these instruments prevents working on more than one instrument at any one time.

SR 3.3.1.9

SR 3.3.1.9 is the performance of a TADOT and is performed every 92 days, as justified in Reference 7.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to RCP undervoltage and underfrequency relays, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.10

A CHANNEL CALIBRATION is performed at every refueling and every 18 months for function 11. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions used in the current unit specific setpoint methodology process that is based on References 10, 11 and 12. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency is based on the calibration interval used for the determination of the magnitude of equipment drift in the setpoint methodology.

SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 24 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. This is needed because the CHANNEL CALIBRATION for the power range neutron detectors consists of a normalization of the detectors based on a power calorimetric and flux map performed above 15% RTP. The CHANNEL CALIBRATION for the source range and intermediate range neutron detectors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data.

This Surveillance is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the unit must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors. 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 when performed on the 24 month Frequency.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.12

SR 3.3.1.12 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 24 months. This SR is modified by a Note stating that this test shall include verification of the rate lag compensation for flow from the core to the RTDs. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of resistance temperature detectors (RTD) sensors, which may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel, is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed element.

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

SR 3.3.1.13

SR 3.3.1.13 is the performance of a COT of RPS interlocks every 24 months.

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, Turbine Trip, and the SI Input from ESFAS. This TADOT is performed every 24 months. The test shall independently verify the OPERABILITY of the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and Reactor Trip Bypass Breakers. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience. The SR is modified by a Note that excludes verification of setpoints from the TADOT. The Functions affected have no setpoints associated with them.

(continued)

BASES

REFERENCES

1. FSAR, Chapter 7.
2. FSAR, Chapter 6.
3. FSAR, Chapter 14.
4. IEEE-279-1968
5. 10 CFR 50.49.
6. Deleted.
7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
8. Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975.
9. WCAP-14384, Implementation of RPS Technical Specification Relaxation Programs, Rev. 0, January 1996.
10. Regulatory Guide 1.105, Revision 3, Instrument Setpoints for Safety Related Systems.
11. ANSI / ISA S67.04.01-2000, Setpoints for Nuclear Safety-Related Instrumentation.
12. ISA-67.04-2000, Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation.

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS instrumentation is segmented into three distinct but interconnected modules as identified below:

- Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured;

- Signal processing equipment including analog protection system, field contacts, and protection channel sets: provide signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications; and

- ESFAS automatic initiation relay logic: initiates the proper engineered safety feature (ESF) actuation in accordance with the defined logic and based on the bistable outputs from the signal process control and protection system.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Protection System (RPS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical

(continued)

BACKGROUND (continued)

allowances are provided in the trip setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria.

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. These setpoints are defined in FSAR, Chapter 6 (Ref. 1), Chapter 7 (Ref. 2), and Chapter 14 (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the ESFAS relay logic for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the ESFAS relay logic, while others provide input to the ESFAS relay logic, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used for input to the protection circuits only, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of- two logic.

Generally, if a parameter is used for input to the ESFAS relay logic and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The

(continued)

BACKGROUND (continued)

circuit is designed to withstand both an input failure to the control control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

These requirements are described in IEEE-279-1968 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2 and discussed later in these Technical Specification Bases.

Trip Setpoints and Allowable Values

The following describes the relationship between the safety limit, analytical limit, allowable value and channel component calibration acceptance criteria:

a. A Safety Limit (SL) is a limit on the combination of THERMAL POWER, RCS highest loop average temperature, and RCS pressure needed to protect the integrity of physical barriers that guard against the uncontrolled release of radioactivity (i.e., fuel, fuel cladding, RCS pressure boundary and containment). The safety limits are identified in Technical Specification 2.0, Safety Limits (SLs).

b. An Analytical Limit (AL) is the trip actuation point used as an input to the accident analyses presented in FSAR, Chapter 14 (Ref. 3). Analytical limits are developed from event analyses models which consider parameters such as process delays, rod insertion times, reactivity changes, instrument response times, etc. An analytical limit for a trip actuation point is established at a point that will ensure that a Safety Limit (SL) is not exceeded.

c. An Allowable Value (AV) is the limiting actuation point for the entire channel of a trip function that will ensure, within the required level of confidence, that sufficient allocation exists

(continued)

BACKGROUND (continued)

between this actual trip function actuation point and the analytical limit. The Allowable Value is more conservative than the Analytical Limit to account for instrument uncertainties that either are not present or are not measured during periodic testing. Channel uncertainties that either are not present or are not measured during periodic testing may include design basis accident temperature and radiation effects (current unit specific setpoint methodology process that is based on References 10, 11 and 12) or process dependent effects. The channel allowable value for each ESFAS function is controlled by Technical Specifications and is listed in Table 3.3.2-1, Engineered Safety Feature Actuation System Instrumentation.

d. Calibration acceptance criteria (i.e., setpoints) are established by plant administrative programs for the components of a channel (i.e., required sensor, alarm, interlock, display, and trip function). The calibration acceptance criteria are established to ensure, within the required level of confidence, that the Allowable Value for the entire channel will not be exceeded during the calibration interval.

A description of the methodology used to calculate the channel allowable values and calibration acceptance criteria is provided in the current unit specific setpoint methodology process that is based on References 8, 10, 11 and 12.

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

Each channel required to be OPERABLE can be tested on line, as necessary, to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of Reference 2. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section.

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BACKGROUND (continued)

The Allowable Values listed in Table 3.3.2-1 and the trip setpoints calculated to ensure that Allowable Values are not exceeded during the calibration interval are based on the methodology described in calculations performed in accordance with the current unit specific setpoint methodology process that is based on References 10, 11 and 12. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

ESFAS Relay Logic Protection System

The relay logic equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of relay logic, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide ESF actuation for the unit. Each train is packaged in a cabinet for physical and electrical separation to satisfy separation and independence requirements.

The relay logic performs the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the main control room.

The bistable outputs from the signal processing equipment are sensed by the relay logic equipment and combined into logic that represent combinations indicative of various transients. If a required logic combination is completed, the system will send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY, LCO and APPLICABILITY, LCO, and Applicability sections of this Bases.

Each relay logic train has a built in testing capability that can test the decision logic matrix functions and the actuation devices while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed.

(continued)

BACKGROUND (continued)

The actuation of ESF components is accomplished through master and slave relays. The relay logic energizes the master relays appropriate for the condition of the unit. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices. The master and slave relays are routinely tested to ensure operation.

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure-Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function identified in Table 3.3.2-1 to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three and the two-out-of-four configurations allow one channel to be tripped during maintenance

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY, (continued)

or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS.

The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents. ESFAS protection functions are as follows:

1. Safety Injection

Safety Injection (SI) provides two primary functions:

1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to $< 2200^{\circ}F$); and

2. Boration to ensure recovery and maintenance of SDM ($k_{eff} < 1.0$).

These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

- Phase A Isolation;
- Containment Isolation;
- Reactor Trip;
- Turbine Trip;
- Feedwater Isolation;
- Start of auxiliary feedwater (AFW) pumps; and
- Control room ventilation actuation to the CRVS Mode 3 (10% incident mode).

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

These other functions ensure:

- Isolation of nonessential systems through containment penetrations;
- Trip of the turbine and reactor to limit power generation;
- Isolation of main feedwater (MFW) to limit secondary side mass losses;
- Start of AFW to ensure secondary side cooling capability; and
- Isolation of the control room to ensure habitability.

a. <u>Safety Injection-Manual Initiation</u>

The LCO requires one channel per train to be OPERABLE. The operator can initiate both trains of SI at any time by using either of two push buttons in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

Each channel consists of one push button and the interconnecting wiring to the actuation logic cabinet. Each push button actuates both trains. This configuration does not allow testing at power.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

b. Safety Injection-Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

Manual and automatic initiation of SI must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Manual Initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a SI, actuation is simplified by the use of the manual actuation push buttons.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

c. Safety Injection-Containment Pressure-High

This signal provides protection against the following accidents:

- SLB inside containment; and
- LOCA.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

Containment Pressure-High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic. The transmitters (d/p cells) and electronics are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment.

Thus, the high pressure Function will not experience any adverse environmental conditions and the trip setpoint reflects only steady state instrument uncertainties.

Containment Pressure-High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

d. <u>Safety Injection-Pressurizer Pressure-Low</u>

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve;
- SLB;
- Inadvertent opening of a pressurizer relief or safety valve;
- LOCAs; and
- SG Tube Rupture.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

Three channels of pressurizer pressure provide input into the ESFAS actuation logic. These channels initiate the ESFAS automatically when two of the three channels exceed the low pressure setpoint. These protection channels also provide control functions; however, the two-out-of-three logic is considered adequate to provide the required protection.

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod ejection). Therefore, the Allowable Value reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 (above the Pressurizer Pressure Interlock (Function 7) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the Pressurizer Pressure Interlock (Function 7) setpoint. Automatic SI actuation below this pressure setpoint is performed by the Containment Pressure-High signal.

This Function is not required to be OPERABLE in MODE 3 below the Pressurizer Pressure Interlock (Function 7) setpoint. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. <u>Safety Injection- High Differential Pressure Between Steam Lines</u>

Steam Line Pressure — High Differential Pressure Between Steam Lines provides protection against the following accidents:

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

- SLB; and
- Inadvertent opening of an ADV or an SG safety valve.

High Differential Pressure Between Steam Lines provides no input to any control functions. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the requirements, with a two-out-of-three logic on each steam line.

With the transmitters located inside the auxiliary feed pump room, it is possible for them to experience adverse environmental conditions during a HELB event.
Therefore, the surveillance acceptance criterion reflects both steady state and adverse environmental instrument uncertainties.

Steam line high differential pressure must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is not sufficient energy in the secondary side of the unit to cause an accident.

The surveillance acceptance criterion used for this function is #142 psid.

f, g. Safety Injection-High Steam Flow in Two Steam Lines Coincident With T_{avg}-Low or Coincident With Steam Line Pressure-Low

These Functions (1.f and 1.g) provide protection against the following accidents:

- SLB; and
- the inadvertent opening of a SG safety valve.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

Two steam line flow channels per steam line are required OPERABLE for these Functions. The steam line flow channels are combined in a one-out-of-two logic to indicate high steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the Function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements. The one-out-of-two configuration allows online testing because trip of one high steam flow channel is not sufficient to cause initiation. High steam flow in two steam lines is acceptable in the case of a single steam line fault due to the fact that the remaining intact steam lines will pick up the full turbine load. The increased steam flow in the remaining intact lines will actuate the required second high steam flow trip. Additional protection is provided by Function 1.e., High Differential Pressure Between Steam Lines.

One channel of T_{avg} per loop and one channel of low steam line pressure per steam line are required OPERABLE. For each parameter, the channels for all loops or steam lines are combined in a logic such that two channels tripped will cause a trip for the parameter. The Function trips on one-out-of-two high steam flow in any two-out-of-four steam lines if there is one-out-of-one low T_{avg} trip in any two-out-of-four RCS loops, or if there is a one-out-of-one low pressure trip in any two-out-of-four steam lines. Since the accidents that this event protects against cause both low steam line pressure and low T_{avg}, provision of one channel per loop or steam line ensures no single random failure can disable both of these Functions. The steam line pressure channels provide no control inputs. The T_{avg} channels provide control inputs, but the control function cannot initiate events that the Function acts to mitigate.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

The Allowable Value for high steam flow is a linear function that varies with power level. The function is a turbine first stage pressure corresponding to approximately 54% of full steam flow between 0% and 20% load to approximately 120% of full steam flow at 100% load. The nominal trip setpoint is similarly calculated.

With the transmitters located inside the containment (RCS temperature and steam line flow) or inside the auxiliary feedwater building (steam pressure), it is possible for them to experience adverse steady state environmental conditions during an SLB event. Therefore, the Allowable Value reflects both steady state and adverse environmental instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 when any MSIV is open because a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). SLB may be addressed by Containment Pressure High (inside containment) or by High Steam Flow in Two Steam Lines coincident with Steam Line Pressure — Low, for Steam Line Isolation, followed by High Differential Pressure Between Two Steam Lines, for SI. This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an accident.

2. <u>Containment Spray</u>

Containment Spray provides three primary functions:

1. Lowers containment pressure and temperature after an HELB in containment;

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

2. Reduces the amount of radioactive iodine in the containment atmosphere; and
3. Adjusts the pH of the water in the containment and recirculation sump after a large break LOCA.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure;
- Limit the release of radioactive iodine to the environment; and
- Minimize corrosion of the components and systems inside containment following a LOCA.

The containment spray actuation signal starts the containment spray pumps. Water is drawn from the RWST by the containment spray pumps and mixed with sodium tetraborate located in baskets in the sump. When the RWST reaches a specified minimum level, the spray pumps are secured. RHR or recirculation pumps will be used if continued containment spray is required. Containment spray is actuated automatically by Containment Pressure-High High.

a. <u>Containment Spray-Manual Initiation</u>

Manual initiation of containment spray (CS) requires that two pushbuttons in the control room be depressed simultaneously which will actuate both trains of CS. Two pushbuttons must be depressed simultaneously to minimize the potential for an inadvertent actuation of CS which could have serious consequences. Each CS pushbutton closes one of the two contacts required to start CS train A and one of the two contacts required to start CS train B; depressing both pushbuttons closes both of the contacts

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

required to start CS train A and both of the contacts required to start CS train B. Two channels (contacts) are required to be Operable for CS train A and two channels (contacts) are required to be Operable for CS train B. Failure of one manual pushbutton will result in one inoperable channel in both trains.

Note that Manual Initiation of containment spray also actuates Phase B containment isolation and containment ventilation isolation.

b. <u>Containment Spray-Automatic Actuation Logic and Actuation Relays</u>

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of containment spray must be OPERABLE in MODES 1, 2, and 3 when there is a potential for an accident to occur, and sufficient energy in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. Manual initiation is also required in MODE 4, even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the number of components actuated on a containment spray, actuation is simplified by the use of the manual actuation push buttons. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary and secondary systems to result in containment overpressure. In MODES 5 and 6, there is also adequate time for the operators to evaluate unit conditions

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

and respond, to mitigate the consequences of abnormal conditions by manually starting individual components.

c. Containment Spray-Containment Pressure Hi-Hi

This signal provides protection against a LOCA or an SLB inside containment. The transmitters (d/p cells) are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions and the Allowable Value reflects only steady state instrument uncertainties.

This Function requires the bistable output to energize to perform its required action. It is not desirable to have a loss of power actuate containment spray, because the consequences of an inadvertent actuation of containment spray could be serious. Therefore, the IP3 design consists of 2 sets of 3 channels (i.e., 6 pressure instruments) and 2 channels from each set of 3 are required to energize to actuate Containment Spray. This configuration provides sufficient redundancy to prevent a single failure from causing or preventing Containment Spray initiation even when testing with one inoperable channel already in trip. The Required Actions for an inoperable channel associated with this Function decreases the probability of an inadvertent actuation by allowing no more than one channel per set to be placed in trip.

Containment pressure is not used for control; therefore, this arrangement exceeds the minimum redundancy requirements.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

Containment Pressure- High High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to pressurize the containment and reach the Containment Pressure High High setpoint.

3. <u>Containment Isolation</u>

Containment Isolation provides isolation of the containment atmosphere, and selected process systems that penetrate containment. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a large break LOCA.

There are two separate Containment Isolation signals, Phase A and Phase B. Phase A isolation isolates all automatically isolable process lines exiting containment, except component cooling water (CCW) and RCP seal return, at a relatively low containment pressure indicative of primary or secondary system leaks. For these types of events, forced circulation cooling using the reactor coolant pumps (RCPs) and SGs is the preferred (but not required) method of decay heat removal. Since CCW or RCP seal injection and return are required to support RCP operation, not isolating CCW and RCP seal return on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit. Isolating these functions on the low pressure signal may force the use of feed and bleed cooling, which could prove more difficult to control.

Phase A containment isolation is actuated automatically by SI, or manually via the actuation logic. All process lines exiting containment, with the exception of CCW and RCP seal return, are isolated. CCW and RCP seal return are not isolated at this time to permit continued operation of the RCPs with cooling water

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

flow to the thermal barrier heat exchangers and oil coolers. All process lines not equipped with remote operated isolation valves are manually closed, or otherwise isolated, prior to MODE 4 except those manual isolation valves needed to support plant operations.

Manual Phase A Containment Isolation is accomplished by either of two pushbuttons in the control room. Either push button actuates both trains. Note that manual actuation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

The Phase B signal isolates CCW and RCP seal return. This occurs at a relatively high containment pressure that is indicative of a large break LOCA or an SLB. For these events, forced circulation using the RCPs is no longer desirable. Isolating the CCW at the higher pressure does not pose a challenge to the containment boundary because the CCW System is a closed loop inside containment. Although some CCW system components may not meet all of the ASME Code requirements applied to the containment itself, the system is continuously pressurized to a pressure greater than the Phase B setpoint. Thus, routine operation demonstrates the integrity of the system pressure boundary for pressures exceeding the Phase B setpoint. Furthermore, because system pressure exceeds the Phase B setpoint, any system leakage prior to initiation of Phase B isolation would be into containment. Therefore, the combination of CCW System design and Phase B isolation ensures the CCW System is not a potential path for radioactive release from containment.

Phase B containment isolation is actuated by Containment Pressure-High High, or manually, via the actuation logic, as previously discussed. For containment pressure to reach a value high enough to actuate Containment Pressure-High High, a large break LOCA or SLB must have occurred and containment spray must

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

have been actuated. RCP operation will no longer be required and CCW and seal return to the RCPs are, therefore, no longer necessary. The RCPs can be operated with seal injection flow alone and without CCW flow to the thermal barrier heat exchanger.

Manual Phase B Containment Isolation is accomplished by either of two pushbuttons in the control room. Either pushbutton actuates both trains. Manual Phase B Containment Isolation is also initiated by Containment Spray manual pushbuttons. CS pushbuttons are depressed simultaneously, Phase B Containment Isolation and Containment Spray will be actuated in both trains.

a. Containment Isolation-Phase A Isolation

(1) Phase A Isolation-Manual Initiation

Manual Phase A Containment Isolation is actuated by either of two pushbuttons in the control room. Either pushbutton actuates both trains. Note that manual initiation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

(2) Phase A Isolation-Automatic Actuation Logic and Actuation Relays

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.
Manual and automatic initiation of Phase A Containment Isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a Phase A Containment Isolation, actuation is simplified by the use of the manual actuation push buttons. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase A Containment Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase A Isolation-Safety Injection

Phase A Containment Isolation is also initiated by all Functions that initiate SI. The Phase A Containment Isolation requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

b. Containment Isolation-Phase B Isolation

Phase B Containment Isolation is accomplished by Manual Initiation, Automatic Actuation Logic and Actuation Relays, and by Containment Pressure channels (the same channels that actuate Containment Spray, Function 2). The Containment Pressure trip of Phase B Containment Isolation is energized to trip in order to minimize the potential of spurious trips that may damage the RCPs.

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APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

(1) Phase B Isolation-Manual Initiation

Manual Phase B Containment Isolation is accomplished by either of two pushbuttons in the control room. Either pushbutton actuates both trains.

(2) Phase B Isolation-Automatic Actuation Logic and Actuation Relays

Manual and automatic initiation of Phase B containment isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the number of components actuated on a Phase B containment isolation, actuation is simplified by the use of the manual actuation push buttons. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase B containment isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase B Isolation-Containment Pressure Hi-Hi

The basis for containment pressure MODE applicability is as discussed for ESFAS Function 2.c above.

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APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

4. Steam Line Isolation

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Rapid isolation of the steam lines will limit the steam break accident to the blowdown from one SG, even if Main Steam Check Valve fails. For an SLB upstream of the main steam isolation valves (MSIVs), inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident.

a. Steam Line Isolation-Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room. Each main steam isolation valve (MSIV) will close if either of two solenoid valves in parallel (channel A and channel B) are opened. The pair of solenoid valves associated with each MSIV are operated by a single switch and there is a separate switch for each MSIV. Each of these switches actuates two channels. Except for the switch in the control room which is common to both channels, there are two separate and redundant circuits (channel A and channel B) capable of closing each MSIV. Therefore, the LCO requires 2 channels per MSIV and each MSIV is considered a separate Function.

b. Steam Line Isolation-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of steam line isolation must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the RCS and SGs to have an SLB or other accident. This could

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs are closed. In MODES 4, 5, and 6, there is insufficient energy in the RCS and SGs to experience an SLB or other accident releasing significant quantities of energy.

c. Steam Line Isolation-Containment Pressure (Hi-Hi)

This Function actuates closure of the MSIVs in the event of a LOCA or an SLB inside containment to limit the mass and energy release to containment. The transmitters (d/p cells) are located outside containment. Containment Pressure-High-High provides no input to any control functions. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions, and the Allowable Value reflects only steady state instrument uncertainties.

The IP3 design consists of 2 sets of 3 channels and 2 channels from each set of 3 are required to energize to actuate steam line isolation on high pressure in the containment. This is the same logic that initiates Containment Spray. Therefore, this logic is designed to provide sufficient redundancy to prevent a single failure from causing or preventing Containment Spray initiation even when testing with one inoperable channel already in trip. The Required Action for an inoperable channel associated with this Function is modified by a Note that permits no more than one channel per set to be placed in trip to decrease the probability of an inadvertent actuation.

Containment Pressure-High-High must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in the primary and secondary side to pressurize the containment following

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless all MSIVs are closed. In MODES 4, 5, and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure — High-High setpoint.

d, e. Steam Line Isolation — High Steam Flow in Two Steam Lines Coincident with T_{avg}-Low or Coincident With Steam Line Pressure-Low

These Functions (4.d and 4.e) provide closure of the MSIVs during an SLB or inadvertent opening of a safety valve to limit RCS cooldown and the mass and energy release to containment.

These Functions were discussed previously as Functions 1.e. and 1.f.

These Functions must be OPERABLE in MODES 1 and 2, and in MODE 3, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines unless all MSIVs are closed. These Functions are not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

5. Feedwater Isolation

The function of the Feedwater Isolation signal is to stop the excessive flow of feedwater into the SGs. The Function is necessary to mitigate the effects of a high water level in the SGs, which could result in carryover of water into the steam lines and excessive cooldown of the primary system. The SG high water level is due to excessive feedwater flows.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

This Function is actuated by SG Water Level-High High or by an SI signal. The RPS also initiates a turbine trip signal whenever a reactor trip is generated. In the event of SI, the unit is taken off line and the turbine generator must be tripped. The MFW System is also taken out of operation and the AFW System is automatically started. The SI signal was discussed previously.

a. Feedwater Isolation-Safety Injection

Feedwater Isolation is also initiated by all Functions that initiate SI. Therefore, there are two trains of this Function, one initiated by SI train A and one initiated by SI train B.

b. Feedwater Isolation - Steam Generator Water Level- High High

This signal provides protection against excessive feedwater flow. Signals from two-out-of-three channels from any one SG will isolate feedwater flow by closing two MBFPDVs and MBFRVs. The LCO requires three OPERABLE channels per steam generator.

The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause a severe environment in containment. Therefore, the Allowable Value reflects only steady state instrument uncertainties.

Feedwater Isolation Functions must be OPERABLE in MODES 1 and 2 except when all MBFPDVs or MBFRVs and associated low flow bypass valves are closed or isolated by a closed manual valve when the MFW System is in operation. In MODES 3, 4, 5, and 6, the MFW System is not in service and this Function is not required to be OPERABLE.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has two motor driven pumps and a turbine driven pump, making it available during normal unit operation, during a loss of AC power and during a loss of MFW. The normal source of water for the AFW System is the condensate storage tank (CST). Additionally, City Water (CW) may be aligned to AFW to provide a backup water supply. The AFW System is aligned so that upon a motor driven pump start, flow is initiated to the respective SGs immediately.

a. Auxiliary Feedwater-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Auxiliary Feedwater-Steam Generator Water Level-Low Low

SG Water Level-Low Low provides protection against a loss of heat sink due to a loss of MFW and the resulting loss of SG water level.

Signals from two-out-of-three channels from any one SG will start the motor driven AFW pumps. Signals from two-out-of-three channels from any two SGs will start the steam driven AFW pump. The LCO requires three OPERABLE channels per steam generator.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions, the Allowable Value reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

c. <u>Auxiliary Feedwater-Safety Injection</u>

An SI actuation starts the motor driven AFW pumps. The AFW initiation functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

d. <u>Auxiliary Feedwater-Loss of Offsite Power</u>

A turbine trip in conjunction with a loss of offsite power to the safeguards buses will be accompanied by a loss of reactor coolant pumping power and the subsequent need for some method of decay heat removal. The loss of offsite power (Non SI blackout signal) is detected by a voltage drop on 480 V bus 3A and/or 6A. After the DG breaker closes and the bus has voltage, either safeguards bus will start the turbine driven AFW pump 32 together with operator action to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip with loss of offsite power.

The LCO requires two OPERABLE channels, one OPERABLE channel for bus 3A and one OPERABLE channel for bus 6A. Either channel will start the turbine driven AFW pump. Therefore, a single failure of one channel of non-Safety Injection blackout sequence will not result in a loss of Function.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

Functions 6.a through 6.d must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. SG Water Level — Low Low in any operating SG will cause the motor driven AFW pump to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. SG Water Level — Low Low in any two operating SGs will cause the turbine driven pump to start. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

The Allowable Value for this Function is based on anticipated 480 V bus voltage transient conditions to prevent spurious trips and needless disconnection of safety buses from preferred power (Offsite Power). The analytical limit for event analysis purposes is 0 Volts AC (i.e. complete loss of offsite power). The Allowable Value is therefore is conservative relative to the actual operability limit.

e. <u>Auxiliary Feedwater-Trip of Main Feedwater Pumps</u>

A Trip of either MBFW pump is an indication of a potential loss of MFW and the potential need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. Each turbine driven MBFW pump is equipped with a pressure switch on the control oil line for the speed control system. A low pressure signal from this pressure switch indicates a trip of that pump. The single channel associated with each operating MBFP will start both motor driven AFW pumps. However, there is no single failure tolerance for this Function unless both MBFPs are operating.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

This is acceptable because this is a backup method for starting AFW and other Functions, in particular SG Water Level — Low Low, provide the primary protection against a loss of heat sink. The LCO requires one Operable channel for each operating MBFP. A trip of either MBFW pump starts both motor driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

Function 6.e must be OPERABLE in MODES 1 and 2. This ensures that at least one SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of loss of normal feedwater. In MODES 3, 4, and 5, the MBFW pumps are shut down, and thus MBFW pump trip does not require automatic AFW initiation.

7. <u>ESFAS Interlock-Pressurizer Pressure</u>

The Pressurizer Pressure interlock permits a normal unit cooldown and depressurization without actuation of SI. With two-out-of-three pressurizer pressure channels (discussed previously) less than the setpoint, the operator can manually block the Pressurizer Pressure-Low SI signal. With two-out-of-three pressurizer pressure channels above the setpoint, the Pressurizer Pressure-Low SI signal is automatically enabled. The operator can also enable these trips by use of the respective manual blocking switches.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the actuation of SI. The interlock Functions back up manual actions to ensure bypassable functions are in operation under the conditions assumed in the safety analyses. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the setpoint for the requirements of the heatup and cooldown curves to be met.

(continued)

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

The surveillance acceptance criterion for this function is $\leq$1884 psig.

The ESFAS instrumentation satisfies Criterion 3 of 10 CFR 50.36.

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1.

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument Loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

(continued)

ACTIONS (continued)

B.1, B.2.1 and B.2.2

Condition B applies to manual initiation of:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation.

This action addresses the train orientation of the relay logic for the functions listed above. If a channel or train is inoperable, 48 hours is allowed to return it to an OPERABLE status. Note that for containment spray and Phase B isolation, failure of one or both channels in one train renders the train inoperable. Condition B, therefore, encompasses both situations.

The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each Function, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which overall plant risk is reduced. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 4 within an additional 6 hours (60 hours total time).

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 10). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 10, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

ACTIONS

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

Required Action B.2.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

The allowable 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.

C.1, C.2.1 and C.2.2

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation.

(continued)

ACTIONS

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

This action addresses the train orientation of the relay logic and the master and slave relays. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which overall plant risk is reduced. This is done by placing the unit in at least MODE 3 within an additional 6 hours (12 hours total time) and in MODE 4 within an additional 6 hours (18 hours total time).

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 10). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 10, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

The 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.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 8 hours for surveillance testing, provided the other train is OPERABLE.

(continued)

ACTIONS

D.1, D.2.1 and D.2.2

Condition D applies to:

- Containment Pressure-High;
- Pressurizer Pressure-Low;
- High Differential Pressure Between Steam Lines;
- High Steam Flow in Two Steam Lines Coincident With T_{avg}-Low or Coincident With Steam Line Pressure-Low; and
- SG Water level-Low Low.

If one channel is inoperable, 6 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements.

(continued)

ACTIONS

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

Required Actions associated with High Steam Flow in Two Steam Lines Coincident With Tavg-Low or Coincident With Steam Line Pressure-Low are entered by treating Steam Flow, Tavg, and Steam Line Pressure as three separate Functions. The protective action is initiated on one-out-of-two high flow in any two-out-of-four steam lines if there is one-out-of-one low Tavg trip in any two-out-of-four RCS loops, or if there is a one-out-of-one low pressure trip in any two-out-of-four steam lines. This logic is acceptable because a single steam line fault will cause the remaining intact steam lines to pick up the full turbine load with the protective action initiated by the conditions in the non faulted steam lines. Therefore, a maximum of one channel of each of the three Functions may be placed in trip without creating a condition where a single failure will either cause or prevent the protective action.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 6 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 8 hours for surveillance testing of other channels.

The 6 hours allowed to restore the channel to OPERABLE status or to place the inoperable channel in the tripped condition, is justified in Reference 7.

(continued)

ACTIONS

E.1, E.2.1 and E.2.2

Condition E applies to:

- Steam Line Isolation Containment Pressure-(High High);
- Containment Spray Containment Pressure-(High, High); and
- Containment Phase B Isolation Containment Pressure-(High, High).

The IP3 design for the Containment Pressure (High High) ESFAS Function consists of 2 sets of 3 channels. This design requires that 2 channels from each set of 3 are energized to actuate the Containment Spray or Steam Line Isolation Functions. This configuration provides sufficient redundancy to prevent a single failure from causing or preventing containment spray initiation or steamline isolation even when testing with one inoperable channel per set already in trip.

Note that Condition E applies only when no more than one channel in one or both sets is inoperable. Otherwise, entry into LCO 3.0.3 is required. This is required because two inoperable channels from the same set that fail low could result in a loss of containment spray initiation or steamline isolation when a Containment Pressure (High High) ESFAS initiation is required. Additionally, this ensures that no more than one channel per set can be placed in trip which is required to decrease the probability of an inadvertent actuation of containment spray or steamline isolation if additional channels fail high.

An inoperable channel is placed in trip within 6 hours to limit the amount of time that a single failure of a different channel on the same set could result in the failure of containment spray or steamline isolation to actuate.

With no more than one channel from each set in trip, a single failure will not cause or prevent containment spray initiation or steamline isolation. Failure to place an inoperable channel in trip within 6 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows one additional channel to be bypassed for up to 8 hours for surveillance testing.

(continued)

ACTIONS

F.1, F.2.1 and F.2.2

Condition F applies to:

- Manual Initiation of Steam Line Isolation; and
- Loss of Offsite Power (Non Safety Injection).

For the manual MSIV isolation Function, each MSIV will close if either of the two channels required per MSIV is tripped. If one channel is inoperable, the ability to tolerate a single failure is lost but manual isolation capability is maintained. Therefore, an inoperable channel cannot be placed in trip without causing an actuation and the inoperable channel must be restored to Operable to restore single failure protection. Additionally, since a single switch actuates both channels for each MSIV, the failure of a manual switch may result in the failure of both channels and a loss of Function. The specified Completion Time, 48 hours to restore an inoperable channel, is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each MSIV, and the low probability of an event occurring during this interval. Each MSIV is considered a separate Function.

For the Loss of Offsite Power (Non-Safety Injection) Function, either channel (bus 3A or bus 6A) will start the turbine driven AFW pump. If one channel is inoperable, the AFW starting Function for the turbine driven AFW pump on loss of offsite power is maintained by the channel associated with the other bus. Two inoperable channels result in a loss of this Function; therefore, entry into LCO 3.0.3 is required.

For the Loss of Offsite Power (Non-Safety Injection) Function, an inoperable channel cannot be placed in trip without causing an actuation: therefore, an inoperable channel must be restored to Operable. The specified Completion Time, 48 hours to restore an inoperable channel, is reasonable considering that this is a Non-Safety Injection start of the AFW, the availability of manual starting capability, and the low probability of an event occurring during this interval. Additionally, other Functions, in particular SG Water Level-Low Low, provide the primary protection against a loss of heat sink.

If either of these Functions cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

(continued)

ACTIONS

G.1, G.2.1 and G.2.2

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation and AFW actuation Functions.

The action addresses the train orientation of the relay logic and the actuation relays for these functions. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours unless the plant can be placed outside of the Applicable MODE or Conditions by other means (e.g., shutting all MSIVs). 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. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE.

(continued)

ACTIONS

H.1 and H.2

Condition H applies to the automatic actuation logic and actuation relays for the Feedwater Isolation Function.

This action addresses the train orientation of the relay logic and the actuation relays for this Function. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the following 6 hours unless the plant can be placed outside of the Applicable MODE or Conditions by other means (e.g., shutting all MBFPDVs or MBFRVs and associated bypass valves). The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. These Functions are no longer required in MODE 3. Placing the unit in MODE 3 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE.

(continued)

ACTIONS

I.1, I.2 and J.1

Condition I applies to the AFW pump start on trip of either Main Boiler Feedwater pump.

The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. The single channel associated with each operating MBFP will start both motor driven AFW pumps. However, there is no single failure tolerance for this Function unless both MBFPs are operating. Therefore, when a channel is inoperable, Required Action I.1, verifies that one channel associated with an operating MBFP is OPERABLE to ensure that there is no loss of function. Otherwise, entry into LCO 3.0.3 is required. If both MBFPs are operating, Required Action I.2 allows 48 hours to restore redundancy by requiring one channel associated with each operating MBFP to be OPERABLE. Continued operation without redundant channels for 48 hours is acceptable because this is a backup method for starting AFW and other Functions, in particular SG Water Level — Low Low, provide the primary protection against a loss of heat sink.

If the function cannot be returned to an OPERABLE status, 6 hours are allowed by Required Action J.1 to place the unit in MODE 3.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above.

K.1, K.2.1 and K.2.2

Condition K applies to the Pressurizer Pressure interlock.

With one or more channels inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 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. Placing the unit in MODE 4 removes all requirements for OPERABILITY of this interlock.

(continued)

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1. A Note has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Note that each channel of process protection supplies both trains of the ESFAS. When testing an individual channel, the SR is not met until both train A and train B logic are tested.

The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in the setpoint methodology described in the current unit specific setpoint methodology process that is based on References 10, 11 and 12.

SR 3.3.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and reliability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The relay logic is tested every 31 days on a STAGGERED TEST BASIS. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. All possible logic combinations are tested for each protection function required in Table 3.3.2-1. In addition, the master relay is tested.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.2.2 (continued)

This verifies that the logic modules are OPERABLE and that there is a voltage signal path to the master relay coils. The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.3

SR 3.3.2.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is supplied to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. This test is performed every 31 days on a STAGGERED TEST BASIS. The time allowed for the testing (8 hours) and the surveillance interval are justified in Reference 7.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel (with the exception of the transmitter sensing device) will perform the intended Function. Setpoints must be found within the calibration acceptance criteria.

The "as found" and "as left" values must also be recorded and reviewed. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology (Ref. 6).

The Frequency of 92 days is justified in Reference 7.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.5

SR 3.3.2.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the circuit operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation MODE is prevented from operation. Alternately, contact operation may be verified by a continuity check of the circuit containing the slave relay. This test is performed every 24 months. The Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and AFW pump start on trip of either MBFW pump or loss of offsite power (non SI). It is performed every 24 months. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions. The manual initiation Functions have no associated setpoints.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.7

SR 3.3.2.7 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology that is based on References 10, 11 and 12. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency of 24 months is based on the assumption of an 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable.

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapter 7.
3. FSAR, Chapter 14.
4. IEEE-279-1968.
5. 10 CFR 50.49.
6. Deleted.

(continued)

REFERENCES (continued)

7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

8. Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975.

9. Safety Evaluation Report (SER) for IP3 Amendment 224.

10. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

11. Regulatory Guide 1.105, Revision 3, Instrument Setpoints for Safety Related Systems.

12. ANSI / ISA-R67.04.01-2000, Setpoints for Nuclear Safety-Related Instrumentation.

13. ISA-R67.04-2000, Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation.

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display unit variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Accidents (DBAs).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These instruments are identified by unit specific documents (Ref. 1) addressing the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737 (Ref. 3).

The instrument channels required to be OPERABLE by this LCO include two classes of parameters identified during unit specific implementation of Regulatory Guide 1.97. The instruments governed by this LCO are the Type A and Category I variables which are defined as follows:

<u>Type A variables</u> are included in this LCO because they provide the primary information required for the control room operator to take specific manually controlled actions for which no automatic control is provided, and that are required for safety systems to accomplish their safety functions for DBAs.

(continued)

BASES

BACKGROUND (continued)

Category I variables are the key variables deemed risk significant because they are needed to:

- Determine whether other systems important to safety are performing their intended functions;
- Provide information to the operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release; and
- Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat.

These key variables are identified by the unit specific Regulatory Guide 1.97 analyses (Ref. 1). These analyses identify the unit specific Type A and Category I variables and provide justification for deviating from the NRC proposed list of Category I variables.

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the operability of Regulatory Guide 1.97 Type A and Category I variables so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures (these variables are restricted to preplanned actions for the primary success path of DBAs), e.g., loss of coolant accident (LOCA);
- Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function;

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Determine whether systems important to safety are performing their intended functions;
- Determine the likelihood of a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36. Category I, non-Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Category I, non-Type A, variables are important for reducing public risk and therefore, meet Criterion 4 of 10 CFR 50.36.

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses Regulatory Guide 1.97 instruments that have been designated Category I, non-Type A.

The OPERABILITY of the PAM instrumentation provides information about selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 1.

LCO 3.3.3 requires two OPERABLE channels for most functions. Two OPERABLE channels ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident.

(continued)

BASES

LCO (continued)

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

An exception to the two channel requirement is Containment Isolation Valve (CIV) Position. In this case, the important information is the status of the containment penetrations. The LCO requires one position indicator for each active CIV. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

Table 3.3.3-1 provides a list of all Type A and Category I variables identified by the IP3 Regulatory Guide 1.97 analyses, as amended by the NRC's SER (Ref. 1), with one exception. Requirements for RWST level, which is a Type A and Category I variable, are stated in LCO 3.5.4.

Type A and Category I variables are required to meet Regulatory Guide 1.97 Category I (Ref. 2) design and qualification requirements for seismic and environmental qualification, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display.

The Safety Parameter Display System (SPDS) is provided to the Control Room to continuously display information from which plant status can be assessed. The SPDS consists of the Plant Computer and the Qualified Safety Parameters Display System (QSPDS). The Plant Computer displays and alarms critical safety functions (actions which preserve integrity of one or more physical barriers against radiation) in the Control Room and the emergency response facilities. The Plant Computer provides for historical data storage and retrieval capability. The Plant Computer is a partially redundant computer system not designed to seismic and electrical class 1E criteria. The QSPDS is a backup display system and is qualified to seismic and electrical class 1E standards (Ref. 4).

(continued)

BASES

LCO (continued)

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1. Neutron Flux

Neutron Flux indication covering full range of flux that may occur post accident is provided to verify reactor shutdown. Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

To satisfy these requirements, an Excore Neutron Flux Detection System consisting of two detectors (N38, N39) provides two channels of neutron flux indication capable of providing indication from the source range to 100% RTP. The Excore Neutron Flux Detection System is an indication only system that displays on the QSPDS in the Control Room.

2,3. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (Wide Range)

RCS Hot and Cold Leg Temperatures are Category I variables required for verification of core cooling and long term surveillance. RCS cold leg temperature is used in conjunction with RCS hot leg temperature and steam generator pressure to verify the unit conditions necessary to establish natural circulation in the RCS.

This LCO is satisfied by the OPERABILITY of one hot leg channel and one cold leg channel in each of the four RCS loops:

Hot Leg Loop No. 1 (T413A)	Cold Leg Loop No. 1 (T413B)
Hot Leg Loop No. 2 (T423A)	Cold Leg Loop No. 2 (T423B)
Hot Leg Loop No. 3 (T433A)	Cold Leg Loop No. 3 (T433B)
Hot Leg Loop No. 4 (T443A)	Cold Leg Loop No. 4 (T443B)

The channels provide indication over a range of 0 °F to 700°F.

(continued)

BASES

LCO (continued)

Redundancy for the Hot Leg RCS Temperature is provided by the core exit thermocouples (Functions 18, 19, 20 and 21) which is considered a diverse variable for the RCS Hot Leg indication.

Redundancy for the Cold Leg RCS Temperature is provided by Steam Generator Pressure (Function 16).

4. Reactor Coolant System Pressure (Wide Range)

RCS wide range pressure is a Category I variable required for verification of core cooling and RCS integrity long term surveillance.

RCS pressure is used to verify closure of manually closed pressurizer spray line valves and pressurizer power operated relief valves (PORVs). In addition, RCS pressure is used to develop RCS subcooling for determining whether to terminate actuated SI or to reinitiate stopped SI. RCS pressure can also be used:

- to determine when to reset SI and shut off low head SI;
- to manually restart low head SI;
- as reactor coolant pump (RCP) trip criteria; and
- to make a determination on the nature of the accident in progress and where to go next in the procedure.

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization;
- to verify termination of depressurization; and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

(continued)

BASES

LCO (continued)

RCS pressure and pressurizer level are also used to determine whether to operate the pressurizer heaters.

RCS pressure is a Type A variable because the operator uses this indication to monitor the depressurization of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this indication.

The LCO requirement for RCS Pressure (wide range) indication is satisfied by pressure transmitters designated PT-402 and PT-403. Normal control room indication or recorders or displays on the QSPDS in the Control Room will satisfy this requirement. Pressurizer pressure instrumentation (PT-455, PT-456, PT-457, and PT-474) is available as a diverse means of monitoring RCS pressure.

5. <u>Reactor Vessel Water Level</u>

Reactor Vessel Water Level is required for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy.

This requirement is satisfied by the two channels of the Reactor Vessel Level Indicating System (RVLIS-A and RVLIS-B). The RVLIS automatically compensates for variations in fluid density as well as for the effects of reactor coolant pump operation.

The level reading represents the amount of liquid mass that is in the reactor vessel. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory. The level instrumentation is divided into the full range and the dynamic range in order to measure level under all conditions. The full range gives level indication from the bottom of the reactor vessel to the top of the reactor head during natural circulation conditions. The dynamic range gives indication of reactor vessel liquid level for any combination of running RCP's.

(continued)

BASES

LCO (continued)

6,7. <u>Containment Water Level (Wide Range) and Recirculation Sump Level</u>

Containment Water Level is required for verification and long term surveillance of RCS integrity.

Containment Water Level is used for accident diagnosis and provides a diverse indication for RWST level regarding when to begin the recirculation procedure.

The LCO requirement for Containment Water Level indication is satisfied by level transmitters designated LT-1253 and LT-1254. The LCO requirement for Recirculation Sump Water Level indication is satisfied by transmitters designated LT-1251 and LT-1252. Normal control room recorders or QSPDS display will satisfy this requirement.

8. <u>Containment Pressure (Wide Range)</u>

Containment Pressure (Wide Range) is required for verification of need for and effectiveness of containment spray and fan cooler units.

The LCO requirement for Containment pressure indication is satisfied by pressure transmitters designated PT-1421 and PT-1422. Normal control room indication or QSPDS display will satisfy this requirement. Containment pressure narrow range instrumentation (PT-948A, B, C and PT-949A, B, C) is available to provide a diverse means of establishing containment pressure.

9. <u>Automatic Containment Isolation Valve Position</u>

CIV Position is provided for verification of Containment OPERABILITY and Phase A and Phase B isolation.

When used to verify Phase A and Phase B isolation, the important information is the isolation status of the containment penetrations.

(continued)

BASES

LCO (continued)

The LCO requires one channel of valve closed position indication in the control room (or at local control stations for valves without control room indication) to be OPERABLE for each active CIV in a containment penetration flow path, i.e., two total channels of CIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active CIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation of each isolable penetration either via indicated status of the active valve, as applicable, and prior knowledge of a passive valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

Note (a) to the Required Channels states that the Function is not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve.

Note that non-automatic containment isolation valves are not provided with position indication. As described in the Bases or LCO 3.6.3, "Containment Isolation Valves, containment isolation valves classified as essential and non-automatic are maintained in the open position and are closed after the initial phases of an accident. Emergency procedures are utilized to control the closing of these valves. Non-essential containment isolation valves are maintained in the closed position and may be opened, if necessary, for plant operation and for only as long as necessary to perform the intended function, under administrative controls described in the Bases for LCO 3.6.3.

10. <u>Containment Area Radiation (High Range)</u>

Containment Area Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

(continued)

BASES

LCO (continued)

The LCO requirement for Containment Area Radiation (high range) monitoring is satisfied by radiation monitors designated R-25 and R-26.

11. Not Used

12. Pressurizer Level

Pressurizer Level is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify that the unit is maintained in a safe shutdown condition.

The LCO requirement for 2 channels of pressurizer level indication is satisfied by any two of the level instruments designated LT-459, LT-460 and LT-461.

13. Steam Generator Water Level (Narrow Range)

SG Water Level is required to monitor operation of decay heat removal via the SGs.

Each Steam Generator (SG) has three narrow range transmitters which span a range from the top of the tube bundles up to the moisture separator.

(continued)

BASES

LCO (continued)

Requirements for steam generator water level indication assume that two of the four steam generators are required for heat removal.

Narrow range SG water level is a Category I, Type A variable used to determine if the SG's are being maintained as an adequate heat sink for decay heat removal and to maintain the SG level and prevent overfill. It is also used to determine whether SI should be terminated and may be used to diagnose an SG tube rupture event. The LCO requirement is satisfied by the following two instruments for each SG:

SG 31	SG 32	SG 33	SG 34
LT-417A	LT-427A	LT-437A	LT-447A
LT-417C	LT-427C	LT-437C	LT-447C

The ‘B-series’ (LI-4x7B) Indication Loops are augmented quality related and are not used to satisfy this LCO requirement.

14. Steam Generator Water Level (Wide Range) and Auxiliary Feedwater Flow

Each steam generator has one level transmitter that spans a range from the tube sheet up to the moisture separator. Wide range SG water level is a Category I, Type A variable used to determine if the SGs are being maintained as an adequate heat sink for decay heat removal. Since there is only one instrument channel per steam generator, Auxiliary Feedwater (AFW) flow instrumentation is credited for providing a redundant means of determining if adequate decay heat removal by the SGs is being maintained. Although not a Category I or Type A variable for IP3, the AFW flow instrument channels provide redundancy for SG wide range level in the event of the limiting single failure of a power supply. The LCO requirement for this function is satisfied by one SG wide range level channel and one AFW flow channel for each steam generator. The instrument channels for SG wide range water level are designated LT-417D, LT-427D, LT-437D, and LT-447D. The instrument channels for AFW flow are designated F1200, F1201, F1202, and F1203.

(continued)

BASES

LCO (continued)

15. Not Used

16. Steam Generator Pressure

Each SG contains 3 transmitters that indicate SG pressure. Requirements for steam generator pressure indication assume that two of the four steam generators are required for heat removal.

SG pressure is a Category I, Type A variable used to determine if a high energy secondary line rupture occurred and which steam generator is faulted. SG pressure is also used as the redundant channel of RCS cold leg temperature for natural circulation determination.

The LCO requirements for steam generator pressure indication is satisfied by any two channels from the following list for each of the four SGs:

SG 31	SG 32	SG 33	SG 34
PT-419A	PT-429A	PT-439A	PT-449A
PT-419B	PT-429B	PT-439B	PT-449B
PT-419C	PT-429C	PT-439C	PT-449C

17. Condensate Storage Tank (CST) Level

CST Level is provided to ensure water supply for auxiliary feedwater (AFW). The CST provides the ensured safety grade water supply for the AFW System.

CST Level is a Type A variable because the control room indication is the primary indication used by the operator.

The DBAs that require AFW are the loss of electric power, steam line break (SLB), and small break LOCA.

(continued)

BASES

LCO (continued)

The CST is the initial source of water for the AFW System. However, as the CST is depleted, manual operator action is necessary to replenish the CST or align suction to the AFW pumps to city water.

The LCO requirement for CST level indication is satisfied by level transmitters designated LT-1128 and LT-1128A. Normal control room indication or displays on the QSPDS in the Control Room will satisfy this requirement.

18, 19, 20, 21. Core Exit Temperature

Core Exit Temperature is required for verification and long term surveillance of core cooling. Core Exit Temperature is used as input for developing RCS Subcooling (Function 24) and is also used for unit stabilization and cooldown control. Core exit temperature also serves as a redundant channel for the RCS Hot Leg Temperature (Function 3).

There are 10 qualified core exit thermocouples (CETs) in each of two trains distributed among the four core quadrants. The LCO requirement for Core Exit Temperature is satisfied in each core quadrant by requiring two core exit temperature channels for that quadrant. An OPERABLE core exit temperature channel consists of two OPERABLE CETs. Both CETs in the channel must be from the same train. Requiring 2 CETs per channel in each of the four quadrants provides assurance that sufficient CETs are available to support evaluation of core radial decay power distribution.

22. Main Steam Line (MSL) Radiation

The MSL radiation monitors are a Type A variable provided to allow detection of a gross secondary side radioactivity release and to provide a means to identify the faulted steam generator. The LCO requirements for MSL radiation indication are satisfied by one channel in each of the 4 MSLs using instruments designated R62A, R62B, R62C, R62D. Steam generator narrow range level (Function 13) serves as the redundant channel for the one MSL radiation monitor provided per loop.

(continued)

BASES

LCO (continued)

23. Gross Failed Fuel Detector

The gross failed fuel detector is a Type A variable provided to allow determination of reactor coolant system radioactivity concentration. The LCO requirement is satisfied by instrument loops R63A and R63B.

24. RCS Subcooling

RCS subcooling is a Type A variable provided to determine whether to terminate actuated SI or to reinitiate stopped SI, to determine when to terminate reactor coolant pump operation, and for unit stabilization and cooldown control. RCS subcooling is calculated and displayed in the plant Qualified Safety Parameter Display System using RCS Wide Range Pressure and Core Exit Temperature. Diverse indication is available using saturation pressure and steam tables.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and pre-planned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

(continued)

BASES

ACTIONS (continued)

A.1

Condition A applies when one or more Functions have one required channel that is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account any remaining OPERABLE channels, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies initiation of actions in Specification 5.6.7. which requires a written report to be submitted to the NRC immediately. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

C.1

Condition C applies when one or more Functions have all required channels for that Function inoperable. Most Functions in Table 3.3.3-1 have two required channels, and the first statement in Condition C addresses those situations when both channels are inoperable. However, there are three Functions (2, 3, and 22) where there is only one channel available for the Function. In these cases, redundancy is provided by instrument channels from another appropriate Function. The last three statements in Condition C address each of these Functions for the situation when the single channel in that Function is inoperable and both channels in the Function used for redundancy are inoperable.

(continued)

BASES

ACTIONS

C.1 (continued)

Required Action C.1 requires restoring one channel in the affected Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation.

Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

Condition D applies when the Required Action and associated Completion Time of Condition C is not met. Required Action D.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1 and E.2

If the Required Action and associated Completion Time of Condition D is not met and Table 3.3.3-1 directs entry into Condition E, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 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.

(continued)

BASES

ACTIONS (continued)

F.1

Alternative means of monitoring neutron flux, condensate storage tank level, main steam line radiation, gross failed fuel, containment isolation valve position indications and containment area radiation are available. These alternate means may be used if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means can be used, the Required Action is not to shut down the unit but rather to follow the directions in Specification 5.6.7, in the Administrative Controls section of the TS.

The report provided to the NRC should discuss the alternate means available, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.2. apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.3.2

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter with the necessary range and accuracy. This SR is modified by a Note that excludes neutron detectors. The calibration method for neutron detectors is described in the Bases of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. Safety Evaluation: Conformance to Regulatory Guide 1.97, Revision 3, for Indian Point 3 (TAC No. 51099), dated April 3, 1991.

2. Regulatory Guide 1.97, Revision 3.

3. NUREG-0737, Supplement 1, "TMI Action Items."

4. FSAR, Section 7.

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown

BASES

BACKGROUND

Remote Shutdown provides the control room operator with sufficient instrumentation and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the main steam safety valves (MSSVs) or the SG atmospheric dump valves (ADVs) can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allows extended operation in MODE 3.

If the control room becomes inaccessible, the operators can establish control at various local control stations and place and maintain the unit in MODE 3. Controls and transfer switches are operated locally at the switchgear, motor control panels, or other local stations. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the local control and instrumentation functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 3 should the control room become inaccessible.

APPLICABLE SAFETY ANALYSES

Remote Shutdown is required to provide equipment at appropriate locations outside the control room to promptly shut down and maintain the unit in a safe condition in MODE 3.

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

(continued)

APPLICABLE SAFETY ANALYSES (continued)

Remote Shutdown capability and requirements for remote shutdown are presented in Reference 2.

Remote Shutdown is considered an important contributor to the reduction of unit risk to accidents and as such meets Criterion 4 of CFR 50.36.

LCO

The Remote Shutdown LCO provides the OPERABILITY requirements of the instrumentation and controls necessary to place and maintain the unit in MODE 3 from a location other than the control room. The instrumentation and controls required are listed in Bases Table B 3.3.4-1.

The controls, instrumentation, and transfer switches are required for:

- Core reactivity control (initial and long term);
- RCS pressure control;
- Decay heat removal via the AFW System and the MSSVs or SG ADVs;
- RCS inventory control via charging flow; and
- Safety support systems for the above Functions, including service water, component cooling water, and onsite power, including the diesel generators.

A Function of a Remote Shutdown is OPERABLE if all instrument and control channels needed to support the Remote Shutdown Function are OPERABLE. In some cases, Table 3.3.4-1 may indicate that the required information or control capability is available from several alternate sources. In these cases, the Function is OPERABLE as long as one channel of any of the alternate information or control sources is OPERABLE.

(continued)

LCO (continued)

The remote shutdown instrument and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure the instruments and control circuits will be OPERABLE if unit conditions require that the plant is shutdown from a location other than the control room.

APPLICABILITY

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

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the facility is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable.

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function listed on Table 3.3.4-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A addresses the situation where one or more required Remote Shutdown Functions are inoperable. This includes any Function listed in Table 3.3.4-1, as well as the control and transfer switches.

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

(continued)

ACTIONS (continued)

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 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

The following Surveillance Requirements are applied to each of the remote shutdown functions in Table B 3.3.4-1, as appropriate.

SR 3.3.4.1

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

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If the channels are within the criteria, it is an indication that the channels are OPERABLE. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1 (continued)

As specified in the Surveillance, a CHANNEL CHECK is only required for those channels which are normally energized.

The Frequency of 31 days is based upon operating experience which demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.4.2

SR 3.3.4.2 verifies each required Remote Shutdown control circuit and transfer switch performs the intended function. This verification is performed locally. Operation of the equipment is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the unit can be placed and maintained in MODE 3 from the local control stations. For Function 1.b in Table B 3.3.4-1, it is noted that local open/closed indication for the reactor trip breakers and reactor trip bypass breakers is a mechanical trip flag; the requirements of SR 3.3.4.2 are applied to Table B 3.3.4-1 Function 1.b for purpose of assuring appropriate surveillance testing in terms of requiring verification that the local open/closed indication for the reactor trip breakers and reactor trip bypass breakers is capable of performing the intended function 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. (However, this Surveillance is not required to be performed only during a unit outage.) Operating experience demonstrates that remote shutdown control channels usually pass the Surveillance test when performed at the 24 month Frequency.

SR 3.3.4.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

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

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.
2. FSAR, Section 7.7.3.

Table B 3.3.4-1 (page 1 of 1)
Remote Shutdown Instrumentation and Controls

FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF FUNCTIONS
1. Reactivity Control	
a. Source Range Neutron Flux	1
b. Reactor Trip Breaker Position	1 per trip breaker
c. Manual Reactor Trip	2
2. Reactor Coolant System (RCS) Pressure Control	
a. Pressurizer Pressure or RCS Wide Range Pressure	1
b. Pressurizer Heaters	1
3. Decay Heat Removal via Steam Generators (SGs)	
a. RCS Hot Leg Temperature (loop 31)	1
b. RCS Cold Leg Temperature (loop 31)	1
c. AFW Controls	1
d. SG Pressure	1
e. SG Level	1
4. RCS Inventory Control	
a. Pressurizer Level	1
b. Charging Pump Controls	1

B 3.3 INSTRUMENTATION

B 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate a DG start if a loss of voltage or degraded voltage condition occurs on a 480 V bus.

Two undervoltage relays are provided on each 480 V bus for detecting a bus undervoltage. Either of the two relays is sufficient to satisfy requirements for the 480 V bus undervoltage Function even though the failure of the one remaining undervoltage relay could result in the failure of one DG to start because there is redundancy in the number of EDGs available. The two undervoltage relays are combined in a one-out-of-two logic per bus to generate an undervoltage signal. The allowable value and trip setpoint for this function is established in accordance with Reference 3. Actuation of these relays will trip the bus supply breaker, initiate load shedding, start the DG, and initiate load sequencing. There is no explicit time delay for this function because the undervoltage protection devices are induction type disc relays. Therefore, the time to actual trip will decrease as a function of voltage decrease below the setpoint.

Two degraded voltage relays are provided on each 480 V bus for detecting degraded bus voltage. The relays are combined in a two-out-of-two logic per bus (to prevent spurious actuation). The allowable value and trip setpoint for this function is established in accordance with the current unit specific setpoint methodology process that is based on References 4, 5 and 6. Function actuation includes a time delay of ≤ 10 seconds if a coincident SI signal indicates accident conditions exist and a time delay of ≤ 45 seconds if no SI signal is generated (i.e., non-accident condition). These time delays ensure proper coordination with plant electrical transients (e.g. large motor starts, fast transfers, etc.). Actuation of these relays will trip the bus supply breaker, which will in turn actuate the undervoltage relays.

(continued)

BASES

BACKGROUND (continued)

The LOP start actuation is described in FSAR, Section 8.2 (Ref. 1).

Trip Setpoints and Allowable Values

Technical Specification Allowable Values are determined based on the relationship between an analytical limit and a calculated trip setpoint. A detailed discussion of the relative position of the safety limit, analytical limit, allowable value and the trip setpoint with respect to the normal plant operation point is presented in the Bases of LCO 3.3.1, Reactor Protection System (RPS) Instrumentation.

A detailed description of the methodology used to calculate the channel and bistable device Allowable Value, including their explicit uncertainties, is provided in the current unit specific setpoint methodology process that is based on References 4, 5 and 6.

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 2, in which a loss of offsite power is assumed.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," include the appropriate DG loading and sequencing delay.

The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36.

LCO

The LCO for LOP DG start instrumentation requires that 1 channel per bus of the undervoltage (480 V bus) Function and two channels per bus of the Degraded Voltage (480 V bus) Function must be OPERABLE in MODES 1, 2, 3 and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, 1 channel per bus of the undervoltage (480 V bus) Function and two channels per bus of the Degraded Voltage (480 V bus) Function must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed.

APPLICABILITY

The LOP DG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the vital bus.

ACTIONS

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

(continued)

BASES

ACTIONS (continued)

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate. A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in the LCO. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the LOP DG start Function with one required channel of the undervoltage function inoperable. Note that LCO 3.3.5 requires that only one of the two undervoltage (480 V bus) channels must be OPERABLE. Therefore, Condition A applies when there is no OPERABLE undervoltage (480 V bus) channel on one or more 480 volt vital bus(es).

If one required channel is inoperable or one or more 480 V buses, Required Action A.1 requires that channel to be restored to OPERABLE status within 1 hour.

The specified Completion Time of 1 hour to restore an undervoltage (480 V bus) channels to OPERABLE status is needed because this Condition represents a loss of the undervoltage DG starting Function for the associated DG. The 1 hour delay in declaring the DG inoperable is acceptable because of the low probability of an event occurring during this interval.

B.1

Condition B applies when one of the two required degraded voltage channels is inoperable on one or more 480 V bus. Required Action B.1 requires placing the inoperable channel in trip so that trip capability is restored to the 2 out of 2 logic used to initiate this Function. The 1 hour Completion Time takes into account the low probability of an event requiring an LOP start occurring during this interval.

(continued)

BASES

ACTIONS (continued)

C.1

Condition C applies to each of the LOP DG start Functions when the Required Action and associated Completion Time for Condition A or B are not met. Condition C also applies when two channels of Degraded Voltage Function inoperable in one or more buses. In this Condition, Function trip capability is lost even if one of the channels is placed in trip as specified in Required Action B.1.

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources — Operating," or LCO 3.8.2, "AC Sources — Shutdown," for the DG made inoperable by failure of the LOP DG start instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT. This test is performed every 31 days. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. The Frequency is based on the known reliability of the relays and controls and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

This SR is modified by a note that excludes verification of setpoints from the TADOT. Since this TADOT applies to 480 V degraded voltage and undervoltage, setpoint verification requires bench calibration and is accomplished during CHANNEL CALIBRATION. The Frequency is based on the known reliability of the relays and industry practice.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay, as applicable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2 (continued)

A CHANNEL CALIBRATION is performed every 24 months for the undervoltage relay and every 18 months for the degraded voltage relay. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency is based on operating experience and is justified by the assumption of the calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis (current unit specific setpoint methodology process that is based on References 4, 5 and 6).

REFERENCES

1. FSAR, Section 8.2.

2. FSAR, Chapter 14.2.

3. Deleted.

4. Regulatory Guide 1.105, Revision 3, Instrument Setpoints for Safety Related Systems.

5. ANSI / ISA S67.04.01-2000, Setpoints for Nuclear Safety-Related Instrumentation.

6. ISA-R67.04-2000, Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation.

B 3.3 INSTRUMENTATION

B 3.3.6 Containment Purge System and Pressure Relief Line Isolation Instrumentation

BASES

BACKGROUND

Containment purge system and pressure relief line isolation instrumentation closes the containment isolation valves in the Pressure Relief Line and the Containment Purge System. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. The Containment Pressure Relief Line may be in use during reactor operation and the Containment Purge System may be in use with the reactor shutdown.

The Containment Purge System consists of the 36-inch containment purge supply and exhaust penetrations. The containment purge supply and exhaust penetrations each include two butterfly valves for isolation. The containment purge exhaust penetration includes two butterfly valves for isolation and can be aligned to discharge to the atmosphere through the plant vent either directly or through the Containment Purge Filter System (i.e., a filter bank with roughing, HEPA and charcoal filters).

The Containment Purge System is isolated when in Modes 1, 2, 3 and 4 in accordance with requirements established in LCO 3.6.3, Containment Isolation Valves. In Modes 5 and 6, the Containment Purge System may be used for containment ventilation. When open, the Containment Purge System isolation valves are automatically closed when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12).

The Containment Purge System isolation capability is not credited for ensuring that 10 CFR 50.67 limits are not exceeded during a fuel handling event (Ref. 2).

The Containment Pressure Relief Line (i.e., Containment Vent) consists of a single 10-inch containment vent line that is used to handle normal pressure changes in the Containment when in Modes 1, 2, 3 and 4. The Containment Pressure Relief Line is equipped with three quick-closing butterfly type isolation valves, one inside and two outside

(continued)

BASES

BACKGROUND (continued)

the containment which isolate automatically as part of Safety Injection ESFAS signal (LCO 3.3.2, Function 1) and Containment Spray ESFAS signal (LCO 3.3.2, Function 2). Automatic isolation of the Containment Pressure Relief Line is also initiated when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12).

Both the Containment Purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief isolation valves (PCV-1190, PCV-1191, and PCV-1192) close when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12). The Safety Injection ESFAS signal (LCO 3.3.2, Function 1) and Containment Spray ESFAS signal (LCO 3.3.2, Function 2) also cause closure of the Containment Purge isolation valves and the containment pressure relief isolation valves. Although not required to satisfy Technical Specification requirements, containment purge and containment pressure relief are also isolated when high radiation levels are detected in the plant vent.

APPLICABLE SAFETY ANALYSES

In MODE 1, 2, 3 or 4, <u>Containment Purge System</u> automatic isolation capability is not required because the Containment Purge System is isolated in accordance with the requirements of LCO 3.6.3, Containment Isolation Valves.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Purge System automatic isolation capability is required because it provides for automatic containment isolation in response to a fuel handling accident. Although Containment Purge System isolation capability is not required to meet 10 CFR Part 50.67 limits during a fuel handling accident, this function provides a backup to the filtering function assumed in the analysis and is required to provide containment isolation following the event.

In MODE 1, 2, 3 or 4, <u>Containment Pressure Relief Line</u> automatic isolation capability is required as part of the containment isolation function initiated by the Engineered Safety Feature Actuation System (ESFAS) Instrumentation required by LCO 3.3.2. Containment Pressure Relief Line automatic isolation when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12) provides a backup to the closure initiated by the ESFAS system.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment purge system and pressure relief line isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36.

LCO

The LCO requirements ensure that the instrumentation listed in Table 3.3.6-1, is OPERABLE. This instrumentation is required to initiate automatic isolation of the Containment Purge System and the Containment Pressure Relief Line.

1. <u>Automatic Actuation Logic and Actuation Relays</u>

The LCO requires two trains of Automatic Actuation Logic and Actuation Relays OPERABLE to ensure that no single random failure can prevent automatic actuation.

Automatic Actuation Logic and Actuation Relays are required to be OPERABLE to support the Operability of all of the required functions that isolate the containment purge system and pressure relief line (i.e., gaseous and particulate radiation monitors (R-11 and R-12) and ESFAS SI and containment spray initiation signals). The term Automatic Actuation Logic and Actuation Relays applies to those portions of the circuit that are: 1) common to more than one channel in one train of a single function (i.e., the automatic actuation logic); or, 2) the initiating relay contacts in one train responsible for actuating the equipment and which are common to more than one channel of a single function and more than one function (i.e., the actuation relays). There are two trains of automatic actuation logic and actuation relays for the containment purge system and pressure relief line.

If one or more of the SI or Containment Spray Functions becomes inoperable in such a manner that only the Containment Purge Isolation Function is affected, the Conditions applicable to their SI and Containment Spray Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Purge System and Pressure Relief Line Isolation Functions specify sufficient compensatory measures for this case.

(continued)

BASES

LCO (continued)

2. Containment Radiation Monitors

The LCO specifies two required channels of radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment Purge System Isolation remains OPERABLE. The requirement for two channels is satisfied by the Containment Air Particulate Monitor (R-11) and the Containment Radioactive Gas Monitor (R-12). Allowable values and setpoints for these Functions are specified in the IP3 Offsite Dose Calculation Manual (Ref. 3).

Channel OPERABILITY involves more than OPERABILITY of the channel electronics. OPERABILITY may also require correct valve lineups, sample pump operation, and filter motor operation, as well as detector OPERABILITY, if these supporting features are necessary for trip to occur under the conditions assumed by the safety analyses.

3. ESFAS Function 1, Safety Injection, and ESFAS Function 2, Containment Spray Monitors

Refer to LCO 3.3.2, Functions 1 and 2, for all initiating Functions and requirements.

APPLICABILITY

In MODE 1, 2, 3 or 4, Containment Purge System automatic isolation capability is not required because the Containment Purge System is isolated in accordance with the requirements of LCO 3.6.3, Containment Isolation Valves.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Purge System automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 2, Containment Radiation, are required to be OPERABLE to ensure Containment Purge System isolation in response to a fuel handling accident.

(continued)

BASES

APPLICABILITY (continued)

In MODE 1, 2, 3 or 4, Containment Pressure Relief Line automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 3, ESFAS Safety Injection and ESFAS Containment Spray, are required as part of the containment isolation function initiated by the Engineered Safety Feature Actuation System (ESFAS) Instrumentation required by LCO 3.3.2 Containment Pressure Relief Line automatic isolation Function 2, Containment Radiation, is required as a backup to the closure initiated by the ESFAS system.

While in MODES 5 and 6 without fuel handling in progress, the containment purge system and pressure relief line isolation instrumentation need not be OPERABLE since the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident offsite doses are maintained within the limits of 10 CFR 50.67.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.6-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the failure of either the R-11 or the R-12 radiation monitor channel. Since the two containment radiation monitors measure different parameters, failure of a single channel may result in delay of the radiation monitoring Function for certain

(continued)

BASES

ACTIONS (continued)

A.1 (continued)

events. However, 7 days is allowed to restore the affected channel because the containment radiation monitoring function is not the primary method of ensuring that 10 CFR limits are not exceeded.

B.1

Condition B applies to all Containment Pressure Relief Line Isolation Functions and addresses the train orientation of these Functions. It also addresses the failure of both radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1.

If a train is inoperable, multiple channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action for the applicable Conditions of LCO 3.6.3 is met for each valve made inoperable by failure of isolation instrumentation. A Note is added stating that Condition B is only applicable in MODE 1, 2, 3, or 4.

C.1 and C.2

Condition C applies to all Containment Purge System Isolation Functions and addresses the train orientation of these Functions. It also addresses the failure of both radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1. If a train is inoperable, multiple channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action to place and maintain Containment Purge System isolation valves in their closed position is met or the applicable Conditions of LCO 3.9.3, "Containment Penetrations," are met for each valve made inoperable by failure of isolation instrumentation. The Completion Time for these Required Actions is Immediately.

A Note states that Condition C is applicable during CORE ALTERATIONS and during movement of irradiated fuel assemblies within containment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.6-1 determines which SRs apply to which Containment Purge System and Pressure Relief Line Isolation Functions.

SR 3.3.6.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred, and a CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. A CHANNEL CHECK for a single channel instrument is satisfied by verification that the sensor or the signal processing equipment has not drifted outside its limits.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.6.2

SR 3.3.6.2 is the performance of an ACTUATION LOGIC TEST. This test is performed every 31 days on a STAGGERED TEST BASIS. The Surveillance interval is acceptable based on instrument reliability and industry operating experience.

SR 3.3.6.3

A COT is performed every 92 days on each radiation monitoring channel to ensure the entire channel will perform the intended Function. This test verifies the capability of the instrumentation to provide the containment purge system and pressure relief line isolation. The setpoint shall be left consistent with the current unit specific calibration procedure tolerance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.4

SR 3.3.6.4 is the performance of a TADOT. This test is a check every 24 months that includes actuation of the end device (i.e., valve cycles, etc.).

The test also includes trip devices that provide actuation signals directly to the actuation instrumentation, bypassing the analog process control equipment. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

The Frequency is based on the known reliability of the Function and the redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.6.5

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. Allowable values and setpoints for these Functions are specified in the IP3 Offsite Dose Calculation Manual (Ref. 3).

The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

REFERENCES

1. FSAR Chapter 14.

2. Safety Evaluation Report (SER) for IP3 Amendment 224.

3. IP3 Offsite Dose Calculation Manual.

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Ventilation System (CRVS) Actuation Instrumentation

BASES

BACKGROUND

The CRVS provides a pressurized control room environment from which the unit can be operated following an uncontrolled release of radioactivity. During CRVS Mode 2 (normal operation), the CRVS provides control room ventilation by introducing a supply of outside air via Damper A. Upon receipt of an actuation signal, the CRVS initiates filtered ventilation and pressurization of the control room CRVS Mode 3 (10% Incident Mode) by closing of Damper A and opening of Damper B. This system is described in the Bases for LCO 3.7.11 (Ventilation), "Control Room Ventilation System."

The control room operator can place the CRVS in the CRVS Mode 3 (10% incident mode) described in the Bases for LCO 3.7.11, by manual mode selector switch in the control room. The CRVS is also actuated by a safety injection (SI) signal. The SI Function is discussed in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation."

On a Safety Injection signal or high radiation in the Control Room (Radiation Monitor R-1), the CRVS will actuate to the incident mode with outside air makeup CRVS Mode 3 (i.e., 10% incident mode). This will cause one of the two filters booster fans to start, the locker room exhaust fan to stop, and CRVS dampers to open or close as necessary to filter incoming outside air. In the event that the first booster fan fails to start, the second booster fan will start after a predetermined time delay.

If for any reason it is required or desired to operate with 100% recirculated air (e.g., toxic gas condition is identified), the CRVS can be placed in the incident mode with no outside air makeup CRVS Mode 4 (i.e., 100% recirculation mode) by remote manually operated switches. The Firestat detector will also initiate CRVS Mode 4 and trips both 31 and 32 CCR A/C units.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations.

The CRVS acts to initiate filtration, and pressurize the control room. These actions are necessary to ensure the control room is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of control room personnel.

In MODES 1, 2, 3, and 4, SI signal actuation ensures initiation of the CRVS during a loss of coolant accident or steam generator tube rupture.

Radiation monitor R-1 is not required for the Operability of the Control Room Ventilation System because control room isolation is initiated by the safety injection signal in MODES 1, 2, 3 and 4 and control room isolation is not credited for maintaining radiation exposure within General Design Criteria 19 limits following a fuel handling accident or gas-decay-tank rupture (Ref. 2).

The CRVS does not actuate automatically in response to toxic gases. Separate chlorine, ammonia and oxygen probes are provided to detect the presence of these gases in the outside air intake. Additionally, monitors in the Control Room will detect low oxygen levels and high levels of chlorine and ammonia. The CRVS may be placed in the incident mode with no outside air makeup (i.e., CRVS Mode 4 100% recirculation mode) to respond to these conditions. Instrumentation for toxic gas monitoring is governed by the IP3 Technical Requirements Manual (TRM) (Ref. 1).

Note that the original CRVS design was not required to meet single failure criteria and, although upgraded from the original design, CRVS does not satisfy all requirements in IEEE-279 for single failure tolerance.

The CRVS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36.

(continued)

BASES

LCO

The LCO requirements ensure that instrumentation necessary to actuate the CRVS to the CRVS Mode 3 (10% incident mode) is OPERABLE.

1. Manual Initiation

The LCO requires two channels OPERABLE because the CRVS mode selector switch has two channels (i.e., one channel for each train). The operator can initiate the CRVS at any time by using the CRVS mode selector switch in the control room. This action will cause actuation of all components in the same manner as the automatic actuation signal.

Each channel includes the common CRVS mode selector switch and the interconnecting wiring to the actuation logic cabinet.

2. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Actuation Logic and Relays OPERABLE to ensure that no single random failure can prevent automatic actuation resulting from an SI signal.

Automatic Actuation Logic and Actuation relays are required to be OPERABLE to support the Operability of the function that starts CRVS (i.e., and ESFAS SI initiation signals). The term automatic actuation logic and actuation relays applies to those portions of the circuit that are: 1) common to more than one channel in one train of a single function (i.e., the automatic actuation logic); or, 2) the initiating relay contacts in one train responsible for actuating the equipment and which are common to more than one channel of a single function and more than one function (i.e., the actuation relays). There are two trains of automatic actuation logic and actuation relays for the containment purge system and pressure relief line.

If the SI functions becomes inoperable in such a manner that only the CRVS function is affected, the Conditions applicable to their SI function need not be entered. The less restrictive Actions specified for inoperability of the CRVS Functions specify sufficient compensatory measures for this case.

3. Safety Injection

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

(continued)

BASES

APPLICABILITY

The CRVS Functions must be OPERABLE in MODES 1, 2, 3 and 4 to ensure a habitable environment for the control room operators.

ACTIONS

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.7-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the manual channels and the actuation logic train Function of the CRVS.

If one channel or train is inoperable in one or more Functions, 7 days are permitted to restore it to OPERABLE status. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.11. If the channel/train cannot be restored to OPERABLE status, CRVS must be placed in the CRVS Mode 3 (i.e., the 10% incident mode). This starts both trains of CRVS because a single switch controls both trains. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

B.1

Condition B applies to the failure of two CRVS actuation trains, or two manual channels. The Required Action is to place CRVS in the CRVS Mode 3 (10% incident mode) within 72 hours. This starts both trains of CRVS because a single switch controls both trains. This accomplishes the actuation instrumentation Function that may have been lost and places the unit in a conservative mode of operation. The 72 hour Completion Time for placing the CRVS in the CRVS Mode 3 (10% incident mode) is consistent with the 72 hour Completion Time in ITS 3.7.11. The Completion Time is acceptable because of the low probability of a DBA occurring during this time period. This ensures appropriate limits are placed upon train inoperability as discussed in the Bases for LCO 3.7.11.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies when the Required Action and associated Completion Time for Condition A or B have not been met. The unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 3). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 3, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

A Note has been added to the SR Table to clarify that Table 3.3.7-1 determines which SRs apply to which CRVS Actuation Functions.

SR 3.3.7.1

An actuation logic test is performed at a frequency of 31 days on a Staggered Test Basis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

This test verifies the capability of the instrumentation to provide the CRVS actuation. The Frequency is based on the known reliability of the system and has been shown to be acceptable through operating experience.

SR 3.3.7.2

SR 3.3.7.2 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and is performed every 24 months. Each Manual Actuation Function is tested up to, and including, the end device (i.e., fan starts, damper cycles, etc.).

The Frequency is based on the known reliability of the Function and has been shown to be acceptable through operating experience. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

REFERENCES

1. IP3 Technical Requirements Manual.
2. Safety Evaluation Report (SER) for IP3 Amendment 224.
3. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.3 INSTRUMENTATION

B 3.3.8 Fuel Storage Building Emergency Ventilation System (FSBEVS) Actuation Instrumentation

BASES

BACKGROUND

The FSBEVS ensures that radioactive materials in the fuel building atmosphere following a fuel handling accident involving handling recently irradiated fuel are filtered and adsorbed prior to exhausting to the environment. The system is described in the Bases for LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS). The system initiates filtered ventilation of the fuel storage building automatically following receipt of a high radiation signal from fuel storage building area radiation monitor, R-5.

High radiation levels detected by the fuel storage building area radiation monitor, R-5, initiates fuel storage building isolation and starts the FSBEVS. These actions function to prevent exfiltration of contaminated air by initiating filtered ventilation, which imposes a negative pressure on the fuel storage building. Following an Area Radiation Monitor (R-5) signal or local manual actuation to the emergency mode of operation, the FSBEVS ventilation supply fans stop automatically and the associated ventilation supply dampers close automatically. The charcoal filter face dampers (inlet and outlet dampers) open automatically, if not already open. Additionally, the rollup coiling truck bay door closes, if open, and the inflatable seals on the man doors are actuated. The FSB exhaust fan continues to operate.

APPLICABLE SAFETY ANALYSES

The FSBEVS ensures that radioactive materials in the fuel storage building atmosphere following a fuel handling accident involving handling recently irradiated fuel are filtered and adsorbed prior to being exhausted to the environment when the FSBEVS is aligned and operates as described in the Bases for LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS). This action reduces the radioactive content in the fuel building

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

exhaust following a LOCA or fuel handling accident so that offsite doses remain within the limits specified in 10 CFR 50.67 (Ref. 1).

The FSBEVS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36.

LCO

The LCO requirements ensure that instrumentation necessary for local manual and automatic actuation of the FSBEVS is OPERABLE.

Manual and automatic FSBEVS actuation instrumentation consists of one channel of Fuel Storage Building Area Radiation Monitor (R-5) and one channel of manual actuation. Manual actuation from the fan house and automatic FSBEVS actuation instrumentation are Operable when both the Fuel Storage Building Area Radiation Monitor (R-5) signal and manual initiation will cause the realignment of the FSBEVS to the accident mode of operation as described in the Bases for LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS).

The setpoint for Fuel Storage Building Area Radiation Monitor (R-5) is established in accordance with the FSAR (Ref. 2).

APPLICABILITY

The manual FSBEVS initiation must be OPERABLE when moving recently irradiated fuel assemblies in the fuel storage building, to ensure the FSBEVS operates to remove fission products associated with leakage after a fuel handling accident involving handling recently irradiated fuel.

High radiation initiation of the FSBEVS must be OPERABLE in any MODE during movement of recently irradiated fuel assemblies in the fuel storage building to ensure automatic initiation of the FSBEVS when the potential for the limiting fuel handling accident exists. Due to radioactive decay, the FSBEVS instrumentation is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 84 hours).

(continued)

BASES

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by Reference 2. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by Reference 2, the channel must be declared inoperable immediately and the appropriate Condition entered.

A.1 and A.2

This condition applies when the manual or automatic FSBEVS initiation capability is inoperable. The Required Action is to immediately place the system in operation as described in the Bases for LCO 3.7.13, FSBEVS. This accomplishes the actuation instrumentation function that may have been lost and places the unit in a accident mode of operation. Alternatively, movement of recently irradiated fuel assemblies in the fuel storage building must be suspended immediately to eliminate the potential for events that could require FSBEVS actuation. The Completion Time of immediately requires that the Required Action be pursued without delay and in a controlled manner.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

A CHANNEL CHECK for a single channel instrument is satisfied by verification that the sensor or the signal processing equipment has not drifted outside its limit.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1 (continued)

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal checks of a channel during normal operational use of the displays associated with the LCO required channel.

SR 3.3.8.2

A COT is performed for both the manual and automatic function once every 92 days to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the FSBEVS actuation. The setpoints shall be left consistent with requirements of Reference 2. The Frequency of 92 days is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating experience. This test is typically performed in conjunction with SR 3.7.13.4 which verifies OPERABILITY of the activated devices.

SR 3.3.8.3

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. The Frequency is based on operating experience and is consistent with the refueling cycle.

REFERENCES

1. 10 CFR 50.67.

2. FSAR, Section 1.3.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operational envelope and controlling to 2235 psig. Pressurizer pressure indications are averaged to provide a value for comparison to the limit. The indicated limit is based on the average of three control board readings. A lower pressure will cause the reactor core to approach DNB limits.

The RCS coolant average loop temperature limit is consistent with full power operation within the nominal operational envelope. RCS average loop temperature is assumed to be the highest indicated value of the Tavg indicators and this value is compared to the limit. The indicated limit is based on the average of three control board readings. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analysis. For the 24-month surveillance, RCS flow rate is determined by performing a heat balance after each refueling at ≥ 90% RTP, calculating the flow rate for each RCS loop, calculating the sum of these loop flow rates, and the sum is compared to the limit. For the 12-hour surveillance, RCS flow rate is determined from the average of the loop flow indications on each RCS loop, calculating the sum of these loop flow rates, and the sum is compared to the limit. The indicated limit is based on the average of two control board readings per RCS loop. A lower RCS flow rate will cause the core to approach DNB limits.

(continued)

BASES

BACKGROUND (continued)

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event. Calculations have shown that reactor heat equivalent to 10% rated power can be removed via the steam generators with natural circulation without violating DNBR limits. This analysis assumed conservative flow resistances including steam generator tube plugging and a locked rotor in each loop (Ref. 1).

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

The pressurizer pressure limit and RCS average temperature limit specified in the COLR correspond to the analytical limits used in the safety analyses, with allowance for measurement uncertainty.

The RCS DNB parameters satisfy Criterion 2 of the NRC Policy Statement.

LCO

This LCO specifies limits on the monitored process variables (i.e., pressurizer pressure, RCS average loop temperature, and RCS total flow rate, to ensure the core operates within the limits assumed in the safety analyses. These variables are contained in the COLR to provide operating and analysis flexibility from cycle to cycle. However, the minimum RCS flow, usually based on maximum analyzed steam generator tube plugging, is retained in the TS LCO. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

(continued)

BASES

LCO (continued)

The RCS flow rate limit of 364,700 gpm allows a measurement uncertainty of 2.9% associated with the average of two control board readings per RCS loop. A thermal design flow of 354,400 gpm and a minimum measured flow of 364,700 gpm (including measurement uncertainty) are assumed in the safety analysis. The control board loop RCS flow indications are normalized to the heat balance RCS loop flow measurements after each refueling.

The pressurizer pressure limit of 2204 psig allows for a measurement uncertainty of 24 psig associated with the average of three control board readings. A minimum value of 2180 psig (including control and measurement uncertainties) is assumed in the safety analysis.

The RCS average loop temperature limit of 576.7^{o}F allows for a measurement uncertainty of 2.8^{o}F associated with the average of three control board readings. A maximum full power average Tavg of 579.5^{o}F (including control deadband and measurement uncertainties) is assumed in the safety analysis. 579.5^{o}F in the safety analysis corresponds to a maximum average Tavg control value of 572.0^{o}F. The COLR provides the RCS average loop temperature limit for the cycle-specific full power average Tavg control value.

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

(continued)

BASES

APPLICABILITY (continued)

The DNBR limit is provided in SL 2.1.1, “Reactor Core SLs.” The conditions which define the DNBR limit are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

ACTIONS

A.1

RCS pressure and RCS average loop temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

If Required Action A.1 is not met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for pressurizer pressure is sufficient to ensure the pressure can be restored to a normal operation, steady state condition following load changes and other expected transient operations. Pressurizer pressure indications are averaged to determine the value for comparison to the LCO limit. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.2

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for RCS average loop temperature is sufficient to ensure the temperature can be restored to a normal operation, steady state condition following load changes and other expected transient operations. RCS average loop temperature is assumed to be the highest indicated value of the Tavg indicators and this is the value that is compared to the acceptance criteria. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.3

The 12 hour Surveillance Frequency for RCS total flow rate is performed using the installed flow instrumentation. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify operation within safety analysis assumptions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.1.4

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance once every 24 months verifies that the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

The Frequency of 24 months reflects the importance of verifying flow after a refueling outage when the core has been altered, SG tubes plugged or other activities performed, which may have caused an alteration of flow resistance.

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until 24 hours after ≥ 90% RTP. This exception is appropriate since the heat balance requires the plant to be at a minimum of 90% RTP to obtain the stated RCS flow accuracies. The Surveillance shall be performed within 24 hours after reaching 90% RTP.

REFERENCES

1. FSAR, Section 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.3, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be negative (except during physics testing) and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot zero power (HZP) is a process variable that is an initial condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

All low power safety analyses assume initial RCS loop temperatures ≥ the HZP temperature of 547°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 7°F, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of 10 CFR 50.36.

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

APPLICABILITY

In MODE 1 and MODE 2 with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

The special test exception of LCO 3.1.8, "MODE 2 PHYSICS TESTS Exceptions," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core

(continued)

BASES

APPLICABILITY (continued)

can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, 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 MODE 2 with k_{eff} < 1.0 within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 2 with k_{eff} < 1.0 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above 540°F every 30 minutes when T_{avg}-T_{ref} deviation, and low T_{avg} alarm is not reset and any RCS loop T_{avg} < 547°F.

The Note modifies the SR. When any RCS loop average temperature is < 547°F and the T_{avg} - T_{ref} deviation, and low T_{avg} alarm are alarming, RCS loop average temperatures could fall below the LCO requirement without additional warning. The SR to verify RCS loop average temperatures every 30 minutes is frequent enough to prevent the inadvertent violation of the LCO.

REFERENCES

1. FSAR, Section 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

10CFR50, Appendix G (Ref 1) establishes the requirements for pressure and temperature limitations to prevent non-ductile failure of the ferrite steel components which are part of the reactor coolant pressure boundary (RCPB). These components include the reactor vessel, the steam generators and the pressurizer. The remainder of the RCPB components are fabricated from either stainless steel or from Nickel alloy materials and therefore are not susceptible to non-ductile fracture in the range of normal operating temperatures. This LCO implements the requirements of 10CFR50, Appendix G.

LCO 3.4.3, Figure 3.4.3-1, Heatup and Inservice Leak Test Limitations for the Reactor Coolant System and Figure, 3.4.3-2, Cooldown Limitations for the Reactor Coolant System contain P/T limit curves for heatup, inservice leak test, and cooldown. These P/T limits were developed in Reference 7.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region. Operation is permitted in the region located to the right and below the curves provided in Figures 3.4.3-1 and 3.4.3-2. Conversely, operation in the region located to the left and above the curves is not permitted. These curves were developed without allowance for instrumentation uncertainties. The curves in the plant operating procedures are adjusted to account for the instrumentation uncertainties associated with the actual instruments used to implement these curves.

The LCO establishes operating limits that provide a margin to non-ductile failure of the ferritic portions of the reactor coolant pressure boundary (RCPB). Since the reactor vessel is the only RCPB component which is subjected to neutron irradiation embrittlement, it is the most limiting RCS component. However, the remainder of the RCPB components fabricated from ferritic steel (i.e. Steam Generators and Pressurizer) have also been considered in the analysis and were found to be bounded by the beltline region of the reactor vessel.

(continued)

BASES

BACKGROUND (continued)

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system inservice leak tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section XI, Appendix G (Ref.2).

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material will be established periodically using the methodology provided in Regulatory Guide 1.99, Revision 2 (Ref. 5). These calculated values are periodically confirmed by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings using the methodology provided in Appendix G to the ASME Section XI Code (Ref. 2).

The P/T limit curves are composite curves established by superimposing limits derived from analyses of those portions of the reactor vessel that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

(continued)

BASES

BACKGROUND (continued)

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can challenge the margins against non-ductile failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36.

LCO

The two elements of this LCO are:

a. The limit curves for heatup, and inservice leak test, and cooldown; and

b. Limits on the rate of change of temperature.

Figure 3.4.3-1, Heatup and Inservice Leak Test Limitations for the Reactor Coolant System and Figure, 3.4.3-2, Cooldown Limitations for the Reactor Coolant System, contain P/T limit curves for heatup, and inservice leak test, and cooldown, respectively. These figures specify the maximum RCS pressure for various heatup and cooldown rates at any given reactor coolant temperature. The figures provide the limiting RCS pressure and reactor coolant temperature combination for reactor coolant temperature heatup and cooldown rates up to 100^{o}F /hr. Therefore, heatup or cooldown rates that exceed 100^{o}F/hr are not considered to be within the limits of this LCO.

(continued)

BASES

LCO (continued)

The LCO limits apply to all components of the RCS pressure boundary, except the pressurizer. Because the pressurizer is subjected to insurges and outsurges and it is used to control RCS pressure, it experiences higher heatup and cooldown rates which have been analyzed separately.

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, and cooldown P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves. Heatup and cooldown limits are specified in hourly increments (i.e., the heatup and cooldown limits are based on the temperature change averaged over a one hour period). Limit lines for cooldown rates between those presented may be obtained by interpolation.

Violating the LCO limits places the reactor vessel outside of the bounds of the analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existence, size, and orientation of flaws in the vessel material.

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 1). Although the P/T limits were developed for operation during heatup, Inservice Leak test or cooldown (MODES 3, 4, and 5), their Applicability is at all times in keeping with the concern for nonductile failure.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "RCS Minimum Temperature for Criticality"; and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

(continued)

BASES

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed conditions in the analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring Required Action A.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

(continued)

BASES

ACTIONS (continued)

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 500 psig within 36 hours. Note that LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), will also apply and may require limits for operation that are more restrictive than or supplement this limit.

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.

<u>C.1 and C.2</u>

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by analysis.

The immediate Completion Time reflects the urgency of initiating action to restore the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed conditions in the analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline. Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the P/T limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Heatup and cooldown limits are specified in hourly increments (i.e., the heatup and cooldown limits are based on the temperature change averaged over a one hour period). Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time.

Surveillance for heatup, Inservice Leak test and cooldown, may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that only requires this SR to be performed during system heatup, Inservice Leak test and cooldown. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. 10 CFR 50, Appendix G
2. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix G
3. ASTM E185
4. 10 CFR 50, Appendix H
5. Regulatory Guide 1.99, Revision 2, May 1988
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E
7. WCAP-17954-P, Rev 0, “Indian Point 3 Heatup and Cooldown Limit Curves for Normal Operation,” December 2014

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops — MODES 1 and 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid;

d. Providing a second barrier against fission product release to the environment; and

e. Removing the heat generated in the fuel due to fission product decay following a unit shutdown.

The reactor coolant is circulated through four loops connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

Calculations have shown that reactor heat equivalent to 10% rated power can be removed via the steam generators with natural circulation without violating DNBR limits. This analysis assumed conservative flow resistances including steam generator tube plugging and a locked rotor in each loop (Ref.1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service.

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). The transient and accident analyses for the plant have been performed assuming four RCS loops are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the four pump coastdown, single pump locked rotor, single pump (broken shaft or coastdown), and rod withdrawal events (Ref. 1).

Steady state DNB analysis has been performed for the four RCS loop operation. For four RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of 109% RTP. This is the design overpower condition for four RCS loop operation. The value for the accident analysis setpoint of the nuclear overpower (high flux) trip is 108% and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

The plant is designed to operate with all RCS loops in operation to maintain DNBR above the SL, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops — MODES 1 and 2 satisfy Criterion 2 of 10 CFR 50.36.

(continued)

BASES

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG.

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level" (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

(continued)

BASES

ACTIONS

A.1 (continued)

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification every 12 hours that each RCS loop is in operation. Verification can be based on flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

REFERENCES

1. FSAR, Section 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops – MODE 3

BASES

BACKGROUND

In MODE 3, the primary function of the reactor coolant is removal of decay heat and transfer of this heat, via the steam generator (SG), to the secondary plant fluid. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops, connected in parallel to the reactor vessel, each containing an SG, and a reactor coolant pump (RCP). Appropriate flow, pressure, and temperature instrumentation are available for control, protection, and indication. The reactor vessel contains the fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage.

In MODE 3, RCPs are used to provide forced circulation for heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat. However, two RCS loops are required to be OPERABLE to ensure redundant capability for decay heat removal.

Calculations have shown that reactor decay heat equivalent to 10% rated power can be removed via the steam generators with natural circulation. This analysis assumed conservative flow resistances including steam generator tube plugging and a lock rotor in each loop (Ref. 1).

APPLICABLE SAFETY ANALYSES

Whenever the reactor trip breakers (RTBs) are in the closed position and the control rod drive mechanisms (CRDMs) are energized, an inadvertent rod withdrawal from subcritical, resulting in a power excursion, is possible. Such a transient could be caused by a

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Malfunction of the rod control system. In addition, the possibility of a power excursion due to the ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM.

Therefore, in MODE 3 with RTBs in the closed position and Rod Control System capable of rod withdrawal, uncontrolled control rod withdrawal from subcritical is postulated and requires at least two RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are met. For those conditions when the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but only one RCS loop is required to be in operation to be consistent with MODE 3 accident analyses.

Failure to provide decay heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops — MODE 3 satisfy Criterion 3 of 10 CFR 50.36.

LCO

The purpose of this LCO is to require that at least two RCS loops be OPERABLE. In MODE 3 with the RTBs in the closed position and Rod Control System capable of rod withdrawal, two RCS loops must be in operation. Two RCS loops are required to be in operation in MODE 3 with RTBs closed and Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an uncontrolled rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

With the RTBs in the open position, or the CRDMs de-energized, the Rod Control System is not capable of rod withdrawal;

(continued)

BASES

LCO (continued)

therefore, only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is required to be OPERABLE to ensure redundant decay heat removal capability.

The Note permits all RCPs to be not be in operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit performance of required tests or maintenance that can only be performed with all reactor coolant pumps not in operation. The 1 hour time period specified is acceptable because operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by test or maintenance procedures:

a. No operations are permitted that would dilute the RCS boron concentration, thereby maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10 ^{0}F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG, which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with RTBs in the closed position. The least stringent

(continued)

BASES

APPLICABILITY (continued)

condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the RTBs open.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODES 1 and 2";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level" (MODE 6).

ACTIONS

A.1

If one required RCS loop is inoperable, redundancy for forced circulation heat removal is lost. The Required Action is restoration of the required RCS loop to OPERABLE status within the Completion Time of 72 hours. This time allowance is a justified period to be without the redundant, nonoperating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

B.1

If restoration is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the required RCS loop is not in operation, and the RTBs are closed and Rod Control System is capable of rod withdrawal, the Required Action is either to restore the required RCS loop to operation or to de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets. When the RTBs are in the closed position and Rod Control System are capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the RTBs must be opened. The Completion Times of 1 hour to restore the required RCS loop to operation or de-energize all CRDMs is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

D.1, D.2, and D.3

If two required RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining operation for forced circulation heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification can be based on flow rate, temperature, or pump status monitoring, which ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the actual secondary side water level is $\geq$ 71% wide range for each required loop. Depending on plant conditions, either wide range or narrow range SG level instruments may be used to verify this SR is met. Operators may be required to adjust the indicated level to compensate for the effects of SG temperature. If the SG secondary side actual water level is < 71% wide range, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs.

REFERENCES

1. FSAR 14.1.6.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops – MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops connected in parallel to the reactor vessel, each loop containing a SG and a reactor coolant pump (RCP). Appropriate flow, pressure, and temperature instrumentation are available for control, protection, and indication. The RCPs and RHR pumps circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop.

In MODE 4, either RCPs or RHR loops can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCP or one RHR loop for decay heat removal and transport. The flow provided by one RCP loop or RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

When the boron concentration of the RCS is reduced, the process should be uniform to prevent sudden reactivity changes. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump or one

(continued)

BASES

BACKGROUND (continued)

residual heat removal pump is running while boron concentration is being changed. The residual heat removal pump will circulate the primary system volume in approximately one half hour. Boron concentration in the pressurizer is not a concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant.

Calculations have shown that reactor decay heat equivalent to 10% rated power can be removed via the steam generators with natural circulation. This analysis assumed conservative flow resistances including steam generator tube plugging and a lock rotor in each loop (Ref. 1).

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RCS and RHR loops provide this circulation.

The RHR System in conjunction with the CCW and SWS Systems function to cool the unit from RHR entry condition ($T \leq 350°F$) to Mode 5 ($T \leq 200°F$), during normal and post accident operations. The time required to cool from 350°F to 200°F is a function of the number of CCW, SWS and RHR trains operating. As presented in UFSAR, Section 9, two trains of pumps and heat exchangers are usually used to remove residual and sensible heat during normal plant cool-down. If one train of pumps and/or heat exchangers is not operable, safe operation is governed by Technical Specifications and safe shutdown of the plant is not affected; however, the time for cool-down is extended.

RCS Loops — MODE 4 satisfy Criterion 4 of 10 CFR 50.36.

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE in MODE 4 and that one of these loops be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS loops and RHR loops. Any one loop in operation provides enough flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

(continued)

BASES

LCO
(continued)

Note 1 permits all RCPs and RHR pumps to not be in operation for # 1 hour per 8 hour period. The purpose of the Note is to permit performance of required tests or maintenance that can only be performed with no forced circulation. The 1 hour time period is acceptable because operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by test or maintenance procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10 ^{0}F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires that the reactor coolant pump starting requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), must be met before the start of an RCP with any RCS cold leg temperature less than or equal to the LTOP arming temperature. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG, which has the minimum water level specified in SR 3.4.6.2.

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

(continued)

BASES

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of either RCS or RHR provides sufficient circulation for these purposes. However, two loops consisting of any combination of RCS and RHR loops are required to be OPERABLE to meet single failure considerations.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops – MODES 1 and 2";
LCO 3.4.5, "RCS Loops – MODE 3";
LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level" (MODE 6).

ACTIONS

A.1

If one required RCS loop is inoperable and two RHR loops are inoperable, redundancy for heat removal is lost. Action must be initiated to restore a second RCS or RHR loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1

If one required RHR loop is OPERABLE and in operation and there are no RCS loops OPERABLE, an inoperable RCS or RHR loop must be restored to OPERABLE status to provide a redundant means for decay heat removal.

If the parameters that are outside the limits cannot be restored, the unit must be brought to MODE 5 within 24 hours. Bringing the unit to MODE 5 is a conservative action with regard to decay heat removal. With only one RHR loop OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the only OPERABLE RHR loop, it would be safer to initiate that loss from MODE 5 ($\leq$ 200 ^{o}F) rather than MODE 4 (200 to 350 ^{o}F). The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If no loop is OPERABLE or in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RCS or RHR loop to OPERABLE status and in operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that one RCS or RHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance.

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the actual secondary side water level is $\geq$ 71% wide range for each required loop. Depending on plant conditions, either wide range or narrow range SG level instruments may be used to verify this SR is met. Operators may be required to adjust the indicated level to compensate for the effects of SG temperature. If the SG secondary side actual water level is < 71% wide range, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.2 (continued)

The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump and associated support systems. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. FSAR Chapter 14.1.6.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops — MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the steam generator (SG) secondary side coolant, via natural circulation (Ref. 1), or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs, via natural circulation (Ref. 1), are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification. The boron concentration in the pressurizer is of no concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than the rest of the reactor coolant.

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at

(continued)

BASES

BACKGROUND (continued)

least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side water levels $\geq$ 71% wide range to provide an alternate method for decay heat removal via natural circulation (Ref. 1).

When using SGs depending on natural circulation as the backup decay heat removal system in Mode 5, consideration should be given to the potential need for the following: (1) the ability to pressurize and control pressure in the RCS, (2) secondary side water level in the SG relied upon for decay heat removal, (3) availability of a supply of feedwater, and (4) availability of an auxiliary feedwater pump capable of injecting into the relied-upon SGs (Ref.1).

During natural circulation, the SGs secondary side water may boil creating the need to release steam through the atmospheric relief valves or other openings that may exist during shutdown conditions. Therefore, consideration should be given to avoiding the potential for pressurization of the SGs secondary side. It is also important to note that during decay heat removal using natural circulation, a MODE change (MODE 5 to MODE 4) could occur due to heat up of the RCS (Ref.1).

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops – MODE 5 (Loops Filled) satisfy Criterion 4 of 10 CFR 50.36.

(continued)

BASES

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level $\geq$ 71% wide range. One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with secondary side water level $\geq$ 71% wide range. Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

Note 1 permits all RHR pumps to not be in operation # 1 hour per 8 hour period. The purpose of the Note is to permit testing and maintenance that can be performed only when in MODE 5 with no forced circulation. This allowance is acceptable because operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by maintenance or test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10 ^{0}F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during MODE 5 with no forced circulation.

(continued)

BASES

LCO (continued)

Note 3 requires that the reactor coolant pump starting requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), must be met before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature less than the LTOP arming temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP). This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. A SG can perform as a heat sink with forced flow or natural circulation when it has an adequate water level and is OPERABLE.

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be $\geq$ 71% wide range.

Loops filled is based on the ability to use the SGs as a backup means of decay heat removal. The RCS loops are considered filled provided that pressurizer level has been maintained $\geq$10%. The loops are also considered filled following the completion of filling and venting the RCS. The ability to pressurize the RCS to $\geq$100 psig and to control pressure must be established to take credit for use of the SGs as backup decay heat removal. This is to prevent flashing and void formation at the top of the SG tubes

(continued)

BASES

APPLICABILITY (continued)

which may degrade or interrupt the natural circulation flow path (Ref. 1).

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops – MODES 1 and 2";
LCO 3.4.5, "RCS Loops – MODE 3";
LCO 3.4.6, "RCS Loops – MODE 4";
LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side water level < 71% wide range redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and in operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring the secondary side water level $\geq$ 71% wide range ensures an alternate decay heat removal method, via natural circulation, in the event that the second RHR loop is not OPERABLE. Depending on plant conditions, either wide range or narrow range SG level instruments may be used to verify this SR is met. Operators may be required to adjust the indicated level to compensate for the effects of SG temperature.

If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is $\geq$ 71% wide range in at least two SGs, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

(continued)

REFERENCES	1.	NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops — MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat generated in the fuel, and the transfer of this heat to the component cooling water via the residual heat removal (RHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled, only RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR pump for decay heat removal and transport and to require that two loops be available to provide redundancy for heat removal.

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer decay heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop. Separate RHR loops may include common piping and valves.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation. The flow provided by one RHR loop is adequate for heat removal and for boron mixing.

RCS loops in MODE 5 (loops not filled) satisfy Criterion 4 of 10 CFR 50.36.

(continued)

BASES (continued)

LCO

The purpose of this LCO is to require that at least two RHR loops be OPERABLE and one of these loops be in operation. An OPERABLE loop is one that has the capability of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of one running RHR pump meets the LCO requirement for one loop in operation. An additional RHR loop is required to be OPERABLE to meet redundancy considerations.

Note 1 permits all RHR pumps to not be in operation for ≤ 15 minutes. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short (e.g., station blackout testing) and core outlet temperature is maintained ≥ 10° F below saturation temperature. The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop when in MODE 5.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops – MODES 1 and 2";
LCO 3.4.5, "RCS Loops – MODE 3";
LCO 3.4.6, "RCS Loops – MODE 4";
LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level" (MODE 6).

(continued)

BASES (continued)

ACTIONS

A.1

If only one RHR loop is OPERABLE and in operation, redundancy for RHR is lost. Action must be initiated to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two loops for heat removal.

B.1 and B.2

If no required RHR loops are OPERABLE or in operation, except during conditions permitted by Note 1, all operations involving a reduction of RCS boron concentration must be suspended and action must be initiated immediately to restore an RHR loop to OPERABLE status and operation. Boron dilution requires forced circulation for uniform dilution. When required RHR loops are not OPERABLE or in operation, the margin to criticality must not be reduced. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification every 12 hours that one loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.8.2

Verification that the required number of pumps are OPERABLE ensures that additional pumps can be placed in operation, if needed, to maintain decay heat removal and reactor coolant

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.8.2 (continued)

circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level, the required heaters, and emergency power supplies. Pressurizer safety valves and pressurizer power operated relief valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," respectively.

The intent of the LCO is to ensure that a steam bubble exists in the pressurizer prior to power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control.

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant. Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system. Inability to

(continued)

BASES

BACKGROUND (continued)

control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat.

Pressurizer heaters are powered from either the offsite source or the diesel generators (DGs) through the four 480V vital buses as follows: bus 2A (DG 31) supports 415 kW of pressurizer heaters; bus 3A (DG 31) supports 555 kW of pressurizer heaters; bus 5A (DG 33) supports 485 kW of pressurizer heaters; and, bus 6A (DG 32) supports 277 kW of pressurizer heaters.

APPLICABLE SAFETY ANALYSES

In Modes 1. 2, and 3, the LCO requirement on pressurizer water level ensures that a steam bubble exists in the pressurizer. For events that result in pressurizer insurge (e.g., loss of normal feedwater, loss of offsite power and loss of load/turbine trip), the analyses assume that the limiting value for the highest initial pressurizer level is 59.3%. This analytical limit is based on the pressurizer program level of 50.8% at a full power Tavg 572°F plus a conservative 8.5% of span. For other events, the nominal value of pressurizer level is assumed because the effect of the initial pressurizer level on the results is small. The analyses assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present. The limiting scenario for these accident analyses is with the plant at full power. Therefore, the LCO requirement specified for MODE 1 ensures that the pressurizer initial condition assumption remains valid.

Safety analyses presented in the FSAR (Ref. 1) that are examined for pressurizer filling, the loss of normal feedwater and loss of offsite power analyses, assume pressurizer heater operation as operation of the heaters makes the transient results more limiting by contributing to the thermal expansion of the water in the pressurizer.

The maximum pressurizer water level limit, which ensures that a steam bubble exists in the pressurizer, satisfies Criterion 2 of 10 CFR 50.36. The need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

(continued)

BASES

LCO

The pressurizer water level limit is consistent within the nominal operational envelope and controlling to 50.8% level span at a full power Tavg of 572.0°F. The pressurizer water level must be ≤ 54.3% for the pressurizer to be OPERABLE and will ensure that a steam bubble exists. Pressurizer water level indications are averaged to provide a value for comparison to the limit. The indicated limit is based on the average of two control board readings, and allows for a measurement uncertainty of 5%. Whenever pressurizer water level in MODE 3 is above the MODE 1 and 2 limit, a dedicated operator is assigned for operating and controlling the chemical and volume control system, including monitoring pressurizer water level.

Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 150 kW, capable of being powered from either the offsite power source or the emergency power supply. Each of the 2 groups of pressurizer heaters should be powered from a different DG to ensure that the minimum required capacity of 150 kW can be energized during a loss of offsite power condition assuming the failure of a single DG. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The value of 150 kW is sufficient to maintain pressure and is dependent on the heat losses.

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

When RCS temperature is below 380°F, administrative controls in the

(continued)

BASES

APPLICABILITY (continued)

Technical Requirements Manual (Ref. 3) are used to limit the potential for exceeding 10 CFR 50, Appendix G limits.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

ACTIONS

A.1 and A.2

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions.

If the pressurizer water level is not within the limit, action must be taken to place the plant in a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3, with the reactor trip breakers open, within 6 hours and to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

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.

B.1

If one required group of pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering that the redundant heater group is still available and the low probability of an event during this period. Pressure control may be maintained during this time using remaining heaters.

C.1 and C.2

If one group of pressurizer heaters are inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, the

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 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 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Frequency of 12 hours has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is within safety analyses assumptions of ensuring that a steam bubble exists in the pressurizer. Alarms are also available for early detection of abnormal level indications.

SR 3.4.9.2

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. This may be done separately by testing the power supply output and by performing an electrical check on heater element continuity and resistance. The Frequency of 24 months is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

REFERENCES

1. FSAR, Section 14.

2. NUREG-0737, November 1980.

3. IP3 Technical Requirements Manual.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The relief capacity for each valve, 420,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine without a direct reactor trip or any other control. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves; or an increase in the pressurizer relief tank temperature or level; or actuation of acoustic monitors.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4, with one or more RCS cold leg temperatures $\leq 330^{\circ}F$ (i.e., less than the LTOP arming temperature specified in LCO 3.4.12) and MODE 5 and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The upper and lower pressure limits are based on the $\pm$ 1% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

(continued)

BASES

BACKGROUND (continued)

Although the pressurizer safety valves must be set to ± 1% during the Surveillance, the pressurizer safety valves satisfy safety analysis assumptions and meet ASME Code requirements if the setpoint is determined to be ± 3% at the end of the surveillance interval. Therefore, the pressurizer safety valve setpoint is ± 3% for OPERABILITY; however, the valves must be reset to ± 1% during the Surveillance to allow for drift.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure. The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the FSAR (Ref. 2) that require safety valve actuation assume operation of three pressurizer safety valves to limit increases in RCS pressure. No single failure is assumed for spring loaded safety valves designed in accordance with the ASME Boiler and Pressure Vessel Code. The overpressure protection analysis (Ref. 3) is also based on operation of three safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal from full power;

b. Loss of reactor coolant flow;

c. Loss of external electrical load;

d. Loss of normal feedwater;

e. Loss of all AC power to station auxiliaries; and

f. Locked rotor.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation may be required in events a, b, c, e, and f (above) to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions. The pressurizer safety valves satisfy safety analysis assumptions and meet ASME Code requirements if the setpoint is determined to be ± 3% at the end of the surveillance interval.

Pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36.

LCO

The three pressurizer safety valves are set to open at the RCS design pressure (2500 psia), and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits are based on the ± 1% tolerance requirements (Ref. 1) for lifting pressures above 1000 psig.

The pressurizer safety valve setpoint is ± 3% of the nominal 2485 psig setpoint for OPERABILITY; however, the valves must be reset to ± 1% of the nominal 2485 psig setpoint during the Surveillance to allow for drift during the SR interval.

The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the LTOP arming temperature, OPERABILITY of three valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents.

(continued)

APPLICABILITY (continued)

MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require the safety valves for protection.

The LCO is not applicable in MODE 4 when any RCS cold leg temperature is $\leq$ 330°F (i.e., when LCO 3.4.12 is applicable) or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head removed.

The Note allows entry into MODES 3 and 4 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 54 hour exception is based on 18 hour outage time for each of the three valves. The 18 hour period is derived from industry experience that hot testing can be performed in this timeframe.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS overpressure protection. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with any RCS cold leg temperature $\leq$ 330°F (i.e., where LCO 3.4.12 is applicable) within 12 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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

and without challenging plant systems. With any of the RCS cold leg temperatures ≤ 330°F (i.e., when LCO 3.4.12 is applicable) overpressure protection is provided by LTOP. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by three pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is ± 3% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. FSAR, Chapter 14.
3. WCAP-7769, Rev. 1, June 1972.
4. ASME code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs are nitrogen operated valves that are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive leakage or a stuck open PORV. Block valve closure is accomplished manually using controls in the control room. A stuck open PORV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal and alternate pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permit performance of surveillances on the valves during power operation.

The PORVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

Electrical power needed to support the PORVs, their block valves, and their controls is supplied from the vital buses that normally receive power from offsite power sources, but is also capable of being supplied from emergency power sources in the event of a loss of offsite power. Two PORVs and their associated block valves are powered from two separate safety trains (Ref. 1).

(continued)

BASES

BACKGROUND (continued)

The plant has two PORVs, each having a design relief capacity of 179,000 lb/hr at 2335 psig. The functional design of the PORVs is based on maintaining pressure below the Pressurizer Pressure — High reactor trip setpoint following a step reduction of 50% of full load with steam dump and automatic reactor control operation. In addition, the PORVs minimize challenges to the pressurizer safety valves and also may be used for low temperature overpressure protection (LTOP). See LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

APPLICABLE SAFETY ANALYSES

Plant operators employ the PORVs to depressurize the RCS in response to certain plant transients if normal and alternate pressurizer spray are not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs or auxiliary spray are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator.

The PORVs are modeled in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR) criteria are critical (Ref. 2). By assuming PORV manual actuation, the DNBR calculation is more conservative although not required to meet safety limits. As such, this actuation is not required to mitigate these events, and PORV automatic operation is not an assumed safety function.

Pressurizer PORVs satisfy Criterion 3 of 10 CFR 50.36.

LCO

The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation to mitigate the effects associated with an SGTR.

(continued)

LCO (continued)

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open, or closed and energized with the capability to be opened, since the required safety function is accomplished by manual operation. Although typically open to allow PORV operation, the block valves may be OPERABLE when closed to isolate the flow path of an inoperable PORV that is capable of being manually cycled (e.g., as in the case of excessive PORV leakage). Similarly, isolation of an OPERABLE PORV does not render that PORV or block valve inoperable provided the relief function remains available with manual action.

An OPERABLE PORV is required to be capable of manually opening and closing, and not experiencing excessive seat leakage. Excessive seat leakage, although not associated with a specific acceptance criteria, exists when conditions dictate closure of the block valve to limit leakage. Satisfying the LCO helps minimize challenges to fission product barriers.

APPLICABILITY

In MODES 1, 2, and 3, the PORV and its block valve are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. The most likely cause for a PORV small break LOCA is a result of a pressure increase transient that causes the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. The most rapid increases will occur at the higher operating power and pressure conditions of MODES 1 and 2. The PORVs are also required to be OPERABLE in MODES 1, 2, and 3 for manual actuation to mitigate a steam generator tube rupture event.

Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high. Therefore, the LCO is applicable in MODES 1, 2, and 3. The LCO is not applicable in MODE 4, 5 and 6 with the reactor vessel head in place when both pressure and core energy are decreased and the pressure surges become much less significant. LCO 3.4.12 addresses the PORV requirements in these MODES.

(continued)

ACTIONS

A Note has been added to clarify that all pressurizer PORVs are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis).

A.1

PORVs may be inoperable and capable of being manually cycled (e.g., excessive seat leakage). In this condition, either the PORVs must be restored or the flow path isolated within 1 hour. The associated block valve is required to be closed, but power must be maintained to the associated block valve, since removal of power would render the block valve inoperable. This permits operation of the plant until the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition.

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

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

If one PORV is inoperable and not capable of being manually cycled, it must be either restored, or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Time of 1 hour is reasonable, based on challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is at least one PORV that remains OPERABLE, an additional 7 days is provided to restore the inoperable PORV to OPERABLE status. If the PORV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or place the associated PORV in the closed position (i.e., switch in manual control). The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. Because at least one PORV remains OPERABLE, the operator is permitted a Completion Time of 7 days to restore the inoperable block valve to OPERABLE status. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORVs may not be capable of mitigating an overpressure event if the inoperable block valve is not full open. If the block valve is restored within the Completion Time of 7 days, the power will be restored to the PORV. If it cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

D.1 and D.2

If the Required Action of Condition A, B, or C is not met, then 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 6 hours and to MODE 4 within 12 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. In MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

(continued)

ACTIONS (continued)

E.1, E.2, E.3 and E.4

If more than one PORV is inoperable and not capable of being manually cycled, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If no PORVs are restored within the Completion Time, then 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 6 hours and to MODE 4 within 12 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. In MODES 4 and 5, maintaining PORV OPERABILITY may be required. See LCO 3.4.12.

F.1 and F.2

If more than one block valve is inoperable, it is necessary to either restore the block valves within the Completion Time of 1 hour, or place the associated PORVs in manual control (i.e., closed position) and restore at least one block valve within 2 hours. The Completion Times are reasonable, based on the small potential for challenges to the system during this time and provide the operator time to correct the situation.

G.1 and G.2

If the Required Actions of Condition F are not met, then 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 6 hours and to MODE 4 within 12 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. In MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be opened and closed if needed. The basis for the Frequency of 92 days is the ASME Code (Ref. 3). If the block valve is closed to isolate a PORV that is capable of being manually cycled, the OPERABILITY of the block valve is important because opening the block valve is necessary to permit the PORV to be used for manual control of reactor pressure. If the block valve is closed to isolate an inoperable PORV that is not capable of being manually cycled, the maximum Completion Time to restore the PORV and open the block valve is 7 days, which is well within the allowable limits (25%) to extend the block valve Frequency of 92 days. Furthermore, these test requirements would be completed by the reopening of a recently closed block valve upon restoration of the PORV to OPERABLE status.

The Note modifies this SR by stating that it is not required to be met with the block valve closed, in accordance with the Required Action of this LCO.

SR 3.4.11.2

SR 3.4.11.2 requires a complete cycle of each PORV. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated for mitigation of an SGTR. The Frequency of 24 months is based on a typical refueling cycle and industry accepted practice.

REFERENCES

1. Regulatory Guide 1.32, February 1977.
2. FSAR, Section 14.
3. ASME code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP)

BASES

BACKGROUND

LTOP is established to limit RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. LCO 3.4.12, Figure 3.4.12-1 provides the maximum allowable nominal actuation logic setpoints for the power operated relief valves (PORVs) and the maximum RCS pressure for the coldest existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown because a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause non-ductile failure of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the limits of Reference 1.

When the RHR System is isolated from the RCS, the RHR System is protected from overpressure by two spring loaded relief valves (SI-733A and SI-733B). When the RHR System is not isolated from the RCS, the RHR System is protected from overpressure by a spring loaded relief valve (i.e., AC-1836) which has sufficient capacity to accommodate all 3 charging pumps. However, this relief valve does not have sufficient capacity to ensure that the RHR system does not exceed design pressure limits during a mass addition resulting from an inadvertent injection of one or more high head safety injection (HHSI) pumps. Therefore, LTOP requirements are used to protect the RHR System whenever the RHR System is not isolated from the RCS.

This LCO provides RCS overpressure protection by limiting maximum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability is achieved by not permitting any High Head Safety Injection (HHSI) pumps to be capable of injection into the RCS and

(continued)

BACKGROUND (continued)

isolating the accumulators. The pressure relief capacity requires either two redundant power operated relief valves (PORVs) or a depressurized RCS and an RCS vent of sufficient size. One PORV or the open RCS vent is sufficient to provide overpressure protection to terminate an increasing pressure event. Alternately, if redundant PORVs are not Operable or an RCS vent cannot be established, LTOP protection may be established by limiting the pressurizer level to within limits specified in Figure 3.4.12-2 and Figure 3.4.12-3 consistent with the number of charging pumps and number of high head safety injection (HHSI) pumps capable of injecting into the RCS. This approach is acceptable because pressurizer level can be maintained such that it will either accommodate any anticipated pressure surge or allow operators time to react to any unanticipated pressure surge. When pressurizer level is used to satisfy LTOP requirements, operator action is assumed to terminate the unplanned HHSI pump injection within 10 minutes.

With high pressure coolant input capability limited, the ability to create an overpressure condition by coolant addition is restricted. The LCO does not require the makeup control system deactivated or the safety injection (SI) actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the makeup system can provide adequate flow via the makeup control valve. There is no restriction on the status of charging pumps when LTOP is established using either a PORV or an RCS vent. If conditions require the use of more than one HHSI pump for makeup in the event of loss of inventory, then pumps can be made available through manual actions. Charging pumps and low pressure injection systems are available to provide makeup even when LTOP requirements are applicable.

When configured to provide low temperature overpressure protection, the PORVs are part of the Overpressure Protection System (OPS).

LTOP for pressure relief can consist of either the OPS (two PORVs with reduced lift settings), or a depressurized RCS and an RCS vent of sufficient size. Two PORVs are required for redundancy. One PORV has adequate relieving capability to keep from overpressurization for the required coolant input capability.

PORV Requirements

The Overpressure Protection System (OPS) provides the low temperature overpressure protection by controlling the Power Operated Relief Valves

(continued)

BACKGROUND (continued)

(PORVs) and their associated block valves with pressure setpoints that vary with RCS cold leg temperature. Specifically, cold leg temperature signals from three RCS loops are supplied to three associated function generators that calculate the maximum RCS pressures allowed at those temperatures. The maximum RCS pressure limits at any RCS temperature correspond to the 10 CFR 50, Appendix G, limit curve and are used as the OPS pressure setpoint. Having the setpoints of both valves within the limits in Figure 3.4.12-1 ensures that the Reference 1 limits will not be exceeded in any analyzed event.

In addition to generating the OPS pressure setpoint, the same cold leg temperature signals are used to “arm” the OPS when RCS temperature falls below the temperature at which low temperature overpressure protection is required (330^{o}F). This temperature includes an allowance of 14.4^{o}F for instrument uncertainty and margin. Each PORV opens when a two-out-of-two (temperature and pressure) coincidence logic is satisfied. OPS is "armed" when RCS temperature falls below the temperature that satisfies one half of the two-out-of-two (temperature-pressure) coincidence logic. When OPS is enabled, the PORVs will open if RCS pressure exceeds the calculated pressure setpoint that varies with RCS temperature.

The PORV block valves open when the RCS temperature falls below the OPS arming temperature. Note that the control switches for the PORV and PORV block valves must be in the AUTO position and the OPS states links closed for OPS signals to actuate the PORVs.

Three channels of RCS cold leg temperature are used in the two-out-of-three coincidence logic to satisfy the temperature portion of the two-out-of-two (temperature and pressure) coincidence logic for each PORV. Three channels of RCS pressure are used in a two-out-of-three coincidence logic to satisfy the pressure portion of the two-out-of-two (temperature-pressure) coincidence logic for each PORV. Use of a two-out-of-three coincidence logic for pressure and for temperature ensures that a single failure will not cause or prevent an OPS actuation. Use of two PORVs, each with adequate relieving capability to prevent overpressurization, ensures that a single failure will not prevent an OPS actuation.

When a PORV is opened in an increasing pressure transient, the release of coolant will cause the pressure increase to slow and reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

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BACKGROUND (continued)

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

Multiple methods exist for establishing the required RCS vent capacity including removing or blocking open a PORV and disabling its block valve in the open position. An RCS vent of $\geq$ 2.00 square inches or by a blocked open PORV when no HHSI pump is capable of injecting into the RCS; or, an RCS vent with opening greater than or equal to one pressurizer code safety valve flange and up to two HHSI pumps capable of injecting into the RCS will satisfy LTOP requirements because either configuration ensures pressure limits are not exceed during a transient. Two (2) PORVs open on nitrogen with the associated block valves open and disabled is equivalent to a blocked open PORV with its block valve open and disabled. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses demonstrate that the reactor vessel is adequately protected against exceeding the Reference 6 P/T limits. In MODES 1, 2, and 3, with RCS cold leg temperature exceeding 330^{o}F, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 6 limits. At 330 ^{o}F and below, overpressure prevention falls to two OPERABLE PORVs in conjunction with the Overpressure Protection System (OPS) or to a depressurized RCS and a sufficient sized RCS vent. Each of these means has a limited overpressure relief capability. Alternately, if redundant PORVs are not Operable, Low Temperature Overpressure protection may be maintained by limiting the pressurizer level to within limits specified in Figure 3.4.12-2 and Figure 3.4.12-3 consistent with the number of charging pumps and no high head safety injection (HHSI) pumps capable of injecting into the RCS. This approach is acceptable because pressurizer level can be established to either accommodate any anticipated pressure surge or allow operators time to react to any unanticipated pressure surge.

When the RCS temperature is greater than the LTOP arming temperature but below the minimum temperature at which the pressurizer safety valves lift prior to violation of the 10 CFR 50, Appendix G, limits, administrative controls in the Technical Requirements Manual (TRM) (Ref. 3) are used to limit the potential for exceeding 10 CFR 50, Appendix G, limits. These

(continued)

APPLICABLE SAFETY ANALYSES (continued)

administrative controls may include operating with a bubble in the pressurizer and/or otherwise limiting plant time or activities when the RCS temperature is in the specified range. The use of administrative controls to govern operation above the LTOP arming temperature but below the minimum temperature at which the pressurizer safety valves lift prior to violation of the 10 CFR 50, Appendix G, limits is consistent with the guidance provided in Generic Letter 88-011, NRC Position on Radiation Embrittlement of Reactor Vessel Materials and its Impact on Plant Operations (Ref.2). GL 88-011 states that automatic, or passive, protection of the P-T limits will not be required but administratively controlled when in the upper end of the 10 CFR 50, Appendix G, temperature range.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the Figure 3.4.12-1 curves are revised, LTOP must be re-evaluated to ensure its functional requirements can still be met using the OPS (PORVs) method or the depressurized and vented RCS condition.

Figure 3.4.12-1 contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

<u>Mass Input Type Transients</u>

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch.

<u>Heat Input Type Transients</u>

a. Inadvertent actuation of pressurizer heaters;

b. Loss of RHR cooling; or

c. Reactor coolant pump (RCP) startup with Steam Generator secondary side temperature up to 50^{0} F higher than the RCS primary side temperature.

The following are required during the LTOP MODES to ensure that mass and heat input transients do not occur. This is accomplished by the following:

(continued)

a. Rendering all HHSI pumps incapable of injection;

b. Deactivating the accumulator discharge isolation valves in their closed positions or maintaining accumulator pressure less than the maximum RCS pressure for the coldest existing RCS cold leg temperature allowed by the P/T limit curves provided in Figure 3.4.12-1; and

c. Disallowing start of an RCP unless conditions are established that ensure a RCP pump start will not cause a pressure excursion that will exceed LTOP limits. Required conditions for starting a RCP when LTOP is required include a combination of primary and secondary water temperature differences and Overpressure Protection System (OPS) status or pressurizer level. Meeting the LTOP RCP starting surveillances ensures that these conditions are satisfied prior to a RCP pump start.

The analyses demonstrate that either one PORV or the depressurized RCS and RCS vent can maintain RCS pressure below limits when no HHSI pump is capable of injecting into the RCS. This assumes an RCS vent of $\geq$ 2.00 square inches *or* by a blocked open PORV. Two (2) PORVs open on nitrogen with the associated block valves open and disabled is equivalent to a blocked open PORV with its block valve open and disabled. The same protection can be provided when up to two HHSI pumps are capable of injecting into the RCS assuming an RCS vent with opening greater than or equal to one code pressurizer safety valve flange. Alternately, LTOP requirements can be satisfied by various combinations of pressurizer level, RCS pressure, and RCS injection capability (i.e., maximum number of charging pumps and no HHSI pumps) shown in Figure 3.4.12-2 and 3.4.12-3. These combinations of pressurizer level, RCS pressure, and RCS injection capability satisfy LTOP requirements by ensuring a minimum of 10 minutes for operator action to terminate an unplanned event prior to exceeding maximum allowable RCS pressure. None of the analyses addressed the pressure transient need from accumulator injection, therefore, when RCS temperature is low, the LCO also requires the accumulator isolation when accumulator pressure is greater than or equal to the maximum RCS pressure for the coldest existing RCS cold leg temperature allowed in Figure 3.4.12-1.

If the accumulators are isolated and not depressurized, then the accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions.

The consequences of a loss of coolant accident (LOCA) in LTOP MODE 4 conform to 10 CFR 50.46 and 10 CFR 50, Appendix K (Refs. 4 and 5) requirements by having ECCS OPERABLE in accordance with requirements in LCO 3.5.3, ECCS-Shutdown.

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PORV Performance

Analyses show that the vessel is protected when the PORVs are set to open at or below the limit shown in Figure 3.4.12-1. The setpoints are derived by analyses that model the performance of the LTOP System, assuming the limiting LTOP transient with HHSI not injecting into the RCS. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensures the P/T limits will be met. The OPS setpoint is based on an analysis, with allowances for metal/fluid temperature differences, static head due to elevation differences, and dynamic head from the operation of the reactor coolant pumps and RHR pumps (Ref. 7).

The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are determined using neutron fluence projections and the results of testing of the reactor vessel material irradiation surveillance specimens.

The PORVs are considered active components. Thus, the failure of one PORV is assumed to represent the worst case, single active failure.

RCS Vent Performance

With the RCS depressurized, analyses show that one blocked open PORV with its block valve disabled in the open position (note that a 2 square inches vent path is more conservative than one blocked open PORV) is capable of mitigating the allowed LTOP overpressure transient assuming no HHSI pump and no accumulator injects into the RCS. Two (2) PORVs open on nitrogen with the associated block valves open and disabled is equivalent to a blocked open PORV with its block valve open and disabled. The capacity of a vent this size is greater than the flow of the limiting transient for the LTOP configuration, maintaining RCS pressure less than the maximum pressure on the P/T limit curve. An RCS vent with opening greater than or equal to one pressurizer code safety valve flange and up to two HHSI pumps capable of injecting into the RCS will satisfy LTOP requirements because it ensures pressure limits are not exceeded during a transient.

The RCS vent is passive and is not subject to active failure.

LTOP satisfies Criterion 2 of 10 CFR 50.36.

LCO

This LCO requires that LTOP is OPERABLE. LTOP is OPERABLE when the minimum coolant input and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure

(continued)

mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires that no HHSI pumps be capable of injecting into the RCS and all accumulator discharge isolation valves be closed and de-energized if accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in Figure 3.4.12-1.

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs configured as part of an OPERABLE Overpressure Protection System (OPS); or

b. A depressurized RCS and an RCS vent.

A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is set to the limit required by Figure 3.4.12-1 and testing proves its ability to open at this setpoint, and motive power is available to the two valves and their control circuits.

The OPS is OPERABLE for LTOP when there are three OPERABLE RCS pressure channels and three OPERABLE RCS temperature channels. The OPS is still OPERABLE when an inoperable RCS pressure or temperature channel is in the tripped condition. OPS is considered OPERABLE for meeting LCO 3.4.12 requirements even if one or two RCS cold leg temperatures is above the LTOP Applicability limit.

An RCS vent is OPERABLE when open with an area of $\geq$ 2.00 square inches or by a blocked open PORV with its block valve disabled in the open position. Two (2) PORVs open on nitrogen with the associated block valves open and disabled is equivalent to a blocked open PORV with its block valve open and disabled.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

APPLICABILITY

This LCO is applicable whenever the RHR System is not isolated from the RCS to protect the RHR system piping. When all RCS cold leg temperatures are < 330 ^{o}F, RHR system piping is adequately protected by making the accumulators and all HHSI pumps incapable of injecting into the RCS. Therefore, a Note in the LCO specifies that requirements for the OPS System and/or an RCS vent are not Applicable when all RCS cold leg temperatures are > 330 ^{o}F.

(continued)

BASES

This LCO is applicable to provide protection for the RCS pressure boundary in MODE 4 when any RCS cold leg temperature is $\leq$ 330 ^{o}F, in MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above 330 ^{o}F. When the reactor vessel head is off, overpressurization cannot occur. Although LTOP is not applicable when the RCS temperature is greater than the LTOP arming temperature (i.e., $\geq$ 330 ^{o}F), administrative controls in the Technical Requirements Manual (TRM) (Ref. 3) are used to limit the potential for exceeding 10 CFR 50, Appendix G, limits. LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3, and MODE 4 above 330 ^{o}F when the RHR system is isolated from the RCS.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.

The Applicability is modified by three Notes. Note 1 states that accumulator isolation is only required when the accumulator pressure is more than the maximum RCS pressure for the existing temperature, as allowed by the P/T limit curves. This Note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

Note 2 ensures that LCO 3.4.12 will not prohibit a HHSI pump being energized and aligned to the RCS as needed to support emergency boration or to respond to a loss of RHR cooling.

Note 3 specifies that one HHSI pump may be made capable of injecting into the RCS for a period not to exceed 8 hours to perform pump testing. During testing, administrative controls are used to ensure that HHSI testing will not result in exceeding RCS or RHR system pressure limits.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable LTOP system. There is an increased risk associated with entering MODE 4 from MODE 5 with LTOP inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1, A.2.1 and A.2.2

When one or more HHSI pumps are capable of injecting into the RCS, LTOP assumptions regarding limits on mass input capability may not be met.

(continued)

Therefore, immediate action is required to limit injection capability consistent with the LTOP analysis assumptions and the existing combination of pressurizer level and RCS venting capacity. Required Action A.1 requires restoration with LCO requirements. Required Action A.2 requires verification and periodic re-verification that alternate LTOP configurations are met. The Completion Times of immediately reflects the urgency that one of the acceptable LTOP configurations is established as soon as possible.

B.1, C.1 and C.2

To be considered isolated, an accumulator must have its discharge valves closed and the valve power supply breakers fixed in the open position.

An unisolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required Action C.1 and Required Action C.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to > 330 ^{o}F, an accumulator pressure of 700 psig cannot exceed the LTOP limits if the accumulators are injected. Isolating the RHR system from the RCS ensures that the RHR system is not subjected to accumulator pressure. Depressurizing the accumulators below the LTOP limit from Figure 3.4.12-1 also gives this protection. Additionally, the RHR System must be isolated from the RCS to protect RHR piping from a potential mass addition event.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

D.1

When any RCS cold leg temperature is $\leq$ 330 ^{o}F, with one required PORV inoperable, the PORV must be restored to OPERABLE status within a Completion Time of 7 days. Two PORVs are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time considers the facts that only one of the PORVs is required to mitigate an overpressure transient and that the likelihood of an active failure of the remaining valve path during this time period is very low.

E.1

When both required PORVs are inoperable or the Required Action and associated Completion Time of Condition C or D is not met, an alternate

(continued)

method of low temperature overpressure protection must be established within 8 hours. The acceptable alternate methods of LTOP include the following:

a. Depressurize the RCS and establish an RCS vent path; or

b. Increase all RCS cold leg temperatures to > 330°F and isolate the RHR system from the RCS; or

If the option selected is to depressurize the RCS and establish an RCS vent path, the vent must be sized $\geq$ 2.00 square inches or by a blocked open PORV with its block valve disabled in the open position to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. Two (2) PORVs open on nitrogen with the associated block valves open and disabled is equivalent to a blocked open PORV with its block valve open and disabled. This action is needed to protect the RCPB from a low temperature overpressure event and a possible non-ductile failure of the reactor vessel.

The Completion Time considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

F.1

If LTOP requirements are not met for reasons other than Conditions A, B, C, D or E, LTOP requirements must be re-established by depressurizing the RCS and establishing an RCS vent of $\geq$ 2.00 square inches or by a blocked open PORV with its block valve disabled in the open position within 8 hours. Two (2) PORVs open on nitrogen with the associated block valves open and disabled is equivalent to a blocked open PORV with its block valve open and disabled.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1 and SR 3.4.12.2

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, all HHSI pumps are verified incapable of injecting into the RCS. Additionally, the accumulator discharge isolation valves are verified closed and locked out or the accumulator pressure less than the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in Figure 3.4.12-1.

The HHSI pumps are rendered incapable of injecting into the RCS either through removing the power from the pumps by racking the breakers out or

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by providing isolation of the injection path with the valve de-energized or locked closed under administrative control. Other methods may be employed using at least two independent means to prevent a pump injection such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the pump control switch being placed in Trip Pullout and at least one valve in the discharge flow path being closed or by one valve in the discharge flow path being locked or de-energized closed.

The Frequency of 12 hours is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment.

SR 3.4.12.3

The RCS vent of $\geq$ 2.00 square inches or by a blocked open PORV with its block valve disabled in the open position is proven OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that is not locked.

b. Once every 31 days for a valve that is locked, sealed, or secured in position. A removed pressurizer safety valve, PORV, or Manway Cover fits this category.

The passive vent arrangement must only be open to be OPERABLE. This Surveillance is required to be performed if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12.b.

SR 3.4.12.4

Performance of the CHANNEL CHECK of the Overpressure Protection System (OPS) RCS pressure and temperature channels every 24 hours ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

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The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels. This SR is required only when LCO 3.4.12.a is used to establish LTOP protection.

SR 3.4.12.5

The PORV block valve opens automatically when RCS cold leg temperature is below the OPS arming temperature; however, the valves must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve may be remotely verified open in the control room. This Surveillance is performed only if the PORV is being used to satisfy LCO 3.4.12.a.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required removed, and the manual operator is not required locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation. If closed, the block valve must be de-energized to prevent the valve from re-opening automatically.

The 72 hour Frequency is considered adequate because the PORV block valves are opened automatically by the OPS when below the OPS arming temperature if the valve control is positioned to auto and other administrative controls available to the operator in the control room, such as valve position indication, that verify that the PORV block valve remains open.

SR 3.4.12.6

Performance of a COT is required within 12 hours after decreasing all RCS temperatures to $\leq$ 330 ^{o}F and every 31 days on each required PORV to verify and, as necessary, adjust its lift setpoint. 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 COT 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. The COT will verify the setpoint is within the allowed maximum limits in Figure 3.4.12-1. PORV actuation could depressurize the RCS and is not required.

The 24 month Frequency considers the demonstrated reliability of the Overpressure Protection System and the PORVs.

A Note has been added indicating that this SR is required to be met within 12 hours after decreasing RCS cold leg temperature to $\leq$ 330^{o}F. The 12

(continued)

hour allowance considers the unlikelihood of a low temperature overpressure event during this time.

SR 3.4.12.7

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required every 18 months. Performance of a CHANNEL CALIBRATION of RCS pressure and temperature instruments that support the Overpressure Protection System is required every 24 months. These calibrations verify both the OPS and PORV function and ensure the OPERABILITY of the whole channel so that it responds and the valve opens within the required range and accuracy to known input.

SR 3.4.12.8 and SR 3.4.12.9

The RCP starting prerequisites must be satisfied prior to starting or jogging any reactor coolant pump (RCP) when low temperature overpressure protection is required. The RCP starting prerequisites prevent an overpressure event due to thermal transients when an RCP is started. Plant conditions prior to the RCP start determines whether SR 3.4.12.8 or SR 3.4.12.9 must be satisfied prior to starting any RCP.

The principal contributor to an RCP start induced thermal and pressure transient is the difference between RCS cold leg temperatures and secondary side water temperature of any SG prior to the start of an RCP. The RCP starting prerequisites vary depending on plant conditions but include the following: reactor coolant temperature relative to the LTOP enable temperature; secondary side water temperature of the hottest SG relative to the temperature of the coldest RCS cold leg temperature; and, status of the Overpressure Protection System (OPS). When the OPS is inoperable, additional compensatory requirements are required including limits for the pressurizer level and RCS pressure and temperature. When a pressurizer level is specified as a requirement, the level specified is sufficient to prevent the RCS from going water solid for 10 minutes which is sufficient time for operator action to terminate the pressure transient.

SR 3.4.12.8 is used if secondary side water temperature of the hottest steam generator (SG) is less than or equal to the coldest RCS cold leg temperature. SR 3.4.12.9 is more restrictive and is used if the secondary side water temperature of the hottest steam generator is $\leq 50\,^{o}$F above the coldest RCS cold leg temperature.

RCP starting is prohibited if the hottest steam generator is $> 50\,^{o}$F above RCS cold leg temperature or if neither of the RCP starting prerequisites SRs can be satisfied. The steam generator temperature may be measured using the Control Room instrumentation or, as a backup, from a contact reading off the steam generator's shells. Pressurizer level may be determined using control room instrumentation or alternate methods.

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The FREQUENCY of the RCP starting prerequisites SRs is Within 15 minutes prior to starting any RCP. This means that each of the required verifications must be performed within 15 minutes prior to the pump start and must be met at the time of the pump start.

SR 3.4.12.8 and SR 3.4.12.9 are each modified by two Notes. Note 1 specifies that these SRs are required as a condition for pump starting only when the RCS is below the LTOP arming temperature. Note 2 specifies that meeting either SR 3.4.12.8 or SR 3.4.12.9 ensures that pump starting prerequisites are met.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-011, NRC Position on Radiation Embrittlement of Reactor Vessel Materials and its Impact on Plant Operations.
3. IP3 Technical Requirements Manual.
4. 10 CFR 50, Section 50.46.
5. 10 CFR 50, Appendix K.
6. WCAP-17954-P, "Indian Point 3 Heatup and Cooldown Limit Curves for Normal Operation", December 2014
7. LTR-PCSA-15-16, Revision 1, Indian Point Unit 3: Low Temperature Overpressure Protection (LTOP) Report

3. IP3 Technical Requirements Manual.

4. 10 CFR 50, Section 50.46.

5. 10 CFR 50, Appendix K.

6. WCAP-17954-P, “Indian Point 3 Heatup and Cooldown Limit Curves for Normal Operation”, December 2014

7. LTR-PCSA-15-16, Revision 1, Indian Point Unit 3: Low Temperature Overpressure Protection (LTOP) Report

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE. 10 CFR 50, Appendix A, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

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BASES

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for events resulting in steam discharge to the atmosphere assumes that primary to secondary LEAKAGE from all steam generators (SGs) is one gallon per minute or increases to one gallon per minute as a result of accident induced conditions. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The FSAR (Ref. 2) analysis for SGTR assumes the contaminated secondary fluid is released via safety valves and atmospheric dump valves. The 1 gpm primary to secondary LEAKAGE safety analysis assumption is relatively inconsequential.

The SLB is more limiting for site radiation releases. The safety analysis for the SLB accident assumes 0.3 gpm primary to secondary LEAKAGE is through the affected SG and 1 gpm through all SGs as an initial condition. The dose consequences resulting from the SLB accident are well within the limits defined in 10 CFR 50.67 and the staff approved licensing basis (i.e., a small fraction of these limits).

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36.

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration,

(continued)

BASES

LCO (continued)

resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount and is consistent with the capability of the equipment required by LCO 3.4.15, RCS Leakage Detection Instrumentation. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE, the leakage into closed systems or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE Through Any One SG

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 3). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, “The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day.” The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

(continued)

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

Leakage past PIVs or other leakage into closed systems is that leakage that can be accounted for and contained by a system not directly connected to the atmosphere. Leakage past PIVs or other leakage into closed systems is not included in the limits for either identified or unidentified LEAKAGE but PIV leakage must be within the limits specified for PIVs in LCO 3.4.14, "RCS Pressure Isolation Valves (PIV)." Leakage past PIVs or other leakage into closed systems is quantified before being exempted from the limits for identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE or identified LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists, or primary to secondary LEAKAGE is not within limit, or if unidentified or identified LEAKAGE, cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 5). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 5, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

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ACTIONS

B.1 and B.2 (continued)

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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. In MODE 4, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be met with the reactor at steady state operating conditions and near operating pressure. The surveillance is modified by two Notes. Note 1 states that this SR is not required to be performed in MODES 3 and 4 until 12 hours of steady state operation near operating pressure have been established.

Steady state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful and a Note requires the Surveillance to be met when steady state is established. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the systems that monitor the containment atmosphere radioactivity and the operation of the containment sump pump. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation." It should be noted that LEAKAGE past seals and gaskets, measured leakage past PIVs, and other leakage into closed systems is not pressure boundary LEAKAGE.

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. A Note under the Frequency column states that this SR is required to be performed during steady state operation.

SR 3.4.13.2

This SR verifies that primary to secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.17 “Steam Generator Tube Integrity,” should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 4. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

The Surveillance is modified by a Note which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.2 (continued)

The Surveillance Frequency of 72 hours is a reasonable interval to trend primary to secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 4).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. FSAR, Section 14.
3. NEI 97-06, “Steam Generator Program Guidelines.”
4. EPRI, “Pressurized Water Reactor Primary-to-Secondary Leak Guidelines.”
5. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3), define RCS PIVs as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB), which separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety. The RCS PIVs for which the leakage limits of this LCO apply are listed in FSAR Table 6.7-3.

The PIV leakage limit applies to each individual valve. Leakage through PIVs into closed systems is not included in the limits for either identified or unidentified LEAKAGE in LCO 3.4.13, RCS Operational LEAKAGE. Leakage past PIVs into closed systems is that leakage which can be accounted for and contained by a system not directly connected to the atmosphere.

Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident, that could degrade the ability for low pressure injection.

(continued)

BASES

BACKGROUND (continued)

The basis for this LCO is the 1975 NRC "Reactor Safety Study" (Ref. 4) that identified potential intersystem LOCAs as a significant contributor to the risk of core melt. A subsequent study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs.

PIVs are typically provided to isolate the RCS from the following connected systems:

a. Residual Heat Removal (RHR) System; and

b. Safety Injection System.

Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

Residual Heat Removal System Valves 730 and 731 are the PIVs that isolate the RHR System from the RCS. A failure of valves 730 and 731 when the RCS is at normal operating temperature and pressure will result in an intersystem LOCA in which the containment's protective barrier is bypassed (i.e., a LOCA outside containment) because RCS pressure is significantly greater than RHR System design pressure and the RHR system is outside containment. Therefore, administrative controls ensure that both RHR 730 and 731 are closed and de-activated in MODES 1, 2 and 3 and in MODE 4 when the RHR System is not in operation.

Even though administrative controls provide a high degree of assurance that both RHR suction isolation valves are closed during normal plant operation, there is a significant concern that plant operation could proceed for an extended period of time with one of the RHR suction valves not closed. This situation could result from the failure of an operator to close both valves or inadvertent opening of one of the valves during operation. With this plant status, a single failure of the remaining RHR suction isolation valve will result in a LOCA outside containment (Ref. 10). Due to the potential significance of a LOCA outside containment, each of the RHR suction isolation valves is equipped with an autoclosure interlock (ACI) and an open permissive

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BACKGROUND (continued)

interlock (OPI). The purpose of the OPIs and ACIs is to provide a diverse backup to administrative requirements that ensure that both 730 and 731 are closed to provide a double barrier between the RCS and the RHR System when not in the RHR cooling mode and RCS pressure is above the RHR System design pressure (Ref. 10).

APPLICABLE SAFETY ANALYSES

Reference 4 identified potential intersystem LOCAs as a significant contributor to the risk of core melt. The dominant accident sequence in the intersystem LOCA category is the failure of the low pressure portion of the RHR System outside of containment.

The accident is the result of a postulated failure of the PIVs, which are part of the RCPB, and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. Because the low pressure portion of the RHR System is designed for 600 psig, overpressurization failure of the RHR low pressure line would result in a LOCA outside containment and subsequent risk of core melt.

Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

The RHR isolation valve ACI and OPI provide a diverse backup to administrative requirements to ensure that both RHR suction isolation valves are closed to provide a double barrier between the RCS and the RHR System when not in the RHR cooling mode and RCS pressure is above the RHR System design pressure (Ref. 10). Although the OPI and ACI are not required to provide overpressure protection when RHR is in operation, the nominal setpoints are below the RHR System design pressure (i.e., 600 psig). Additionally, the applicable RHR system piping Code, USAS B3.1, allows an overpressure allowance above the design pressure under transient conditions (Ref. 6). Therefore, even when pump

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

discharge head and maximum instrument uncertainties are considered, the ACI will actuate before the RHR System pressure transient limit is exceeded.

RCS PIV leakage satisfies Criterion 2 of 10 CFR 50.36.

LCO

RCS PIV leakage is leakage into closed systems connected to the RCS. Leakage through PIVs into closed systems is not included in the limits for either identified or unidentified LEAKAGE in LCO 3.4.13, RCS Operational LEAKAGE. Leakage past PIVs into closed systems is that leakage which can be accounted for and contained by a system not directly connected to the atmosphere. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm. The previous criterion of 1 gpm for all valve sizes imposed an unjustified penalty on the larger valves without providing information on potential valve degradation and resulted in higher personnel radiation exposures. A study concluded a leakage rate limit based on valve size was superior to a single allowable value.

Reference 7 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, the observed

(continued)

BASES

LCO (continued)

rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one half power.

The ACIs and OPIs for RHR System Valves 730 and 731 are OPERABLE when they will automatically close and prevent re-opening of the two RHR suction isolation valves when RCS pressure exceeds the setpoints specified in SR 3.4.14.2 and SR 3.4.14.3. The ACIs and OPIs are OPERABLE when the isolation valves are closed and the motor operators de-energized if the interlocks will function as soon as power is restored to the motor operator.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 4, valves in the RHR flow path are not required to meet the leakage limit requirements of this LCO when in, or during the transition to or from, the RHR mode of operation. The ACI and OPI functions are required in MODES 1, 2 and 3 to ensure that both RHR suction valves are closed and remain closed in those MODES. The ACI and OPI functions are required in MODE 4 to ensure that both RHR suction valves are closed when RCS pressure is increased after the RHR System is no longer being used for decay heat removal.

In MODES 5 and 6, leakage limits and RHR ACI and OPI functions are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment.

ACTIONS

The Actions are modified by three Notes. Note 1 provides clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the flow path. Note 2 provides clarification that separate entry into Condition C is allowed for the ACI and the OPI on each RHR suction isolation valve. This is acceptable because these interlocks are a backup to administrative controls that ensure the valves are closed when required. Note 3 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system operability, or isolation of a

(continued)

BASES

ACTIONS (continued)

leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

A.1 and A.2

The flow path must be isolated by two valves. Required Actions A.1 and A.2 are modified by a Note that the valves used for isolation must meet the same leakage requirements as the PIVs and must be within the RCPB or the high pressure portion of the system.

Required Action A.1 requires that the isolation with one valve must be performed within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. The 4 hour Completion Time allows the actions and restricts the operation with leaking isolation valves.

Required Action A.2 specifies that the double isolation barrier of two valves be restored by closing some other valve qualified for isolation or restoring one leaking PIV. The 72 hour Completion Time after exceeding the limit considers the time required to complete the Action and the low probability of a second valve failing during this time period. If use of a closed manual, deactivated automatic, or check valve to isolate leaking PIV renders a required system or component inoperable, then the Required Actions associated with the affected system or component are initiated when the valve is closed.

B.1 and B.2

If leakage cannot be reduced, the system isolated, or the other Required Actions accomplished, the plant must be brought to a MODE in which the overall plant risk is reduced. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. This Action may reduce the leakage and also reduces the potential for a LOCA outside the containment.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 11). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 11, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

C.1 and C.2

The inoperability of one or more ACIs or OPIs renders the RHR suction isolation valves incapable of isolating in response to a high pressure condition and/or incapable of preventing inadvertent opening of the valves at RCS pressures in excess of the RHR systems design pressure. If one or more RHR ACIs or OPIs are inoperable, operation may continue as long as the affected RHR isolation valve is closed and de-activated within 7 days and that status re-verified every 31 days thereafter. These Required Actions and associated Completion Times are acceptable in MODES 1, 2 and 3 because the ACIs or OPIs are backups to administrative controls that ensure both RHR suction isolation valves are closed and de-activated during normal plant operation.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

These Required Actions and associated Completion Times are acceptable in MODE 4 because the ACIs and OPIs do not perform any safety function in MODE 4 and are required only to ensure that both RHR suction valves are closed when RCS pressure is increased after the RHR System is no longer being used for decay heat removal. When the ACIs and OPIs are inoperable in MODE 4, the 7 day Completion Time provides adequate time to repair the interlock or to complete a plant cooldown to place the plant outside the applicable MODES.

Required Action C.1 is modified by a Note that allows RHR System suction isolation valves that are closed in accordance with Required Action C.1 to be opened for 7 days following entry into MODE 4 from MODE 3. This allowance is needed so that the RHR system is available to support plant cooldown. This allowance is acceptable because the ACIs and OPIs do not perform any safety function in MODE 4 other than to ensure that both RHR suction valves are closed when RCS pressure is increased after the RHR System is no longer being used for decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 and Required Action A.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition.

For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing is to be performed every 24 months, a typical refueling cycle, if the plant does not go into MODE 5 for at least 7 days. The 24 month Frequency is consistent with 10 CFR 50.55a(g) (Ref. 8) as contained in the Inservice Testing Program, is within frequency allowed by the American Society of Mechanical Engineers (ASME) Code (Ref. 7), and is based on the need to perform such surveillances under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

In addition, testing must be performed once after the valve has been opened by flow or exercised to ensure tight reseating. PIVs disturbed in the performance of this Surveillance should also be tested unless documentation shows that an infinite testing loop cannot practically be avoided. Testing must be performed within 24 hours after the valve has been reseated. Within 24 hours is a reasonable and practical time limit for performing this test after opening or reseating a valve.

The leakage limit is to be met at the RCS pressure associated with MODES 1 and 2. This permits leakage testing at high differential pressures with stable conditions not possible in the MODES with lower pressures.

Entry into MODES 3 and 4 is allowed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. The Note that allows this provision is complementary to the Frequency of prior to entry into MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 12 months. In addition, this Surveillance is not required to be performed on the RHR System when the RHR System is aligned to the RCS in the shutdown cooling mode of operation. PIVs contained in the RHR shutdown cooling flow path must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

SR 3.4.14.2 and SR 3.4.14.3

Verifying that ACI and OPI function at the required setpoints ensures that both RHR suction isolation valves will be closed and remain closed when RCS pressure is increased after the RHR System is no longer being used for decay heat removal.

The 24 month Frequency is based on the need to perform the Surveillance under conditions that apply during a plant outage. The 24 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

REFERENCES

1. 10 CFR 50.2.

2. 10 CFR 50.55a(c).

3. 10 CFR 50, Appendix A.

(continued)

REFERENCES (continued)

4. WASH-1400 (NUREG-75/014), Appendix V, October 1975.

5. NUREG-0677, May 1980.

6. FSAR Section 6.2.

7. ASME code for Operation and Maintenance of Nuclear Power Plants.

8. 10 CFR 50.55a(g).

9. Generic Letter 87-006, Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves.

10. WCAP-11736-A, Residual Heat Removal System Autoclosure Interlock (ACI) Removal Report.

11. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of Appendix A to 10 CFR 50 (Ref. 1) requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE.

Leakage detection systems must have the capability to detect significant reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE.

Industry practice has shown that water flow changes of 0.5 to 1.0 gpm can be readily detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The Containment Sump Discharge Flow Monitor that includes the Containment Sump Pumps (SP-313 & SP-314), Level Switches (LS-SP313 & LS-SP314), and Containment Sump Flow Integrator/Recorder (comprised of FE-1002A & FE-1002B, FIQ-1002 CPU, FIQ-1002, & FR-1002) with the incorporation of the Operator actions described below provides the capability of detecting a 1 gpm leak within four(4) hours;

- Actions to take upon actuation of the alarm, VC Sump Pump Running (Control Room Panel SFF) log the alarm and review the log to determine the last time the sump was pumped out, and to monitor the other leakage detection methods.

OR

- Initiate a special log to monitor and log 3FR-1024, VC Sump Flow Liquid release Flow (located on Panel FDF) every 4 hours and to monitor the other leakage detection methods when a VC Sump Pump has started. This special log is initiated if the Control Room Alarm, “VC Sump Pump Running” becomes inoperable.

(continued)

BASES

BACKGROUND (continued)

Containment Sump Tank Overflow Control Room alarm is an acceptable instrument to use in place of the VC Sump Pump Running alarm as provided by starting of one of the Containment Sump Pumps because either Control Room alarm can be the initiating alarm for the required monitoring of the various instruments to determine if there is a Reactor Coolant Leak. The use of the Containment Sump Tank Overflow alarm requires procedure controls to control for the setup and the process of using the Containment Sump Pumps and the recording of volume of fluid pumped out of Containment. The use of either the VC Sump Pump Running Control Room alarm or the Containment Sump Tank Overflow Control Room alarm as the early warning to the Operator to initiate actions to evaluate/monitor RCS leakage detection instrumentation provides the required leak detection capability of 1 gpm within 4 hours. In addition, the containment fan cooler unit condensate measuring system is instrumented to alarm for increases of 0.5 to 1.0 gpm. This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. Instrument sensitivities of 10^{-11} µCi/cc radioactivity for particulate monitoring and of 10^{-7} µCi/cc radioactivity for gaseous monitoring are practical for these leakage detection systems. Radioactivity detection systems are included for monitoring both particulate (R-11) and gaseous activities (R-12) because of their sensitivities and rapid responses to RCS LEAKAGE.

An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Dew point temperature measurements can thus be used to monitor humidity levels of the containment atmosphere as an indicator of potential RCS LEAKAGE. A 1^0F increase in dew point is well within the sensitivity range of available instruments.

Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed increases in

(continued)

BASES

BACKGROUND (continued)

liquid flow into or from the containment sump and condensate flow from fan cooler unit condensate measuring system. Humidity level monitoring is considered most useful as an indirect alarm or indication to alert the operator to a potential problem. Humidity monitors are not required by this LCO.

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The relevance of temperature and pressure measurements are affected by containment free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.

APPLICABLE SAFETY ANALYSES

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system response times and sensitivities are described in the FSAR (Ref. 2).

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary.

Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leakage occur detrimental to the safety of the unit and the public.

RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36.

(continued)

BASES

LCO

One method of protecting against large RCS leakage derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump flow monitor, in combination with a gaseous or particulate radioactivity monitor and a containment fan cooler unit condensate measuring system, provides an acceptable minimum. The condensate measuring system associated with any one of the fan cooler unit satisfies the requirement for a fan cooler unit condensate measuring system.

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is to be ≤ 200^0F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

A.1 and A.2

With the required containment sump flow monitor inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere radioactivity monitor or containment fan cooler unit will provide indications of changes in leakage. Together with the atmosphere monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage.

Restoration of the required sump flow monitor to OPERABLE status within a Completion Time of 30 days is required to regain the function after the monitor's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

(continued)

BASES

ACTIONS (continued)

B.1.1, B.1.2, B.2.1 and B.2.2

With both gaseous and particulate containment atmosphere radioactivity monitoring instrumentation channels inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere radioactivity monitors. Alternatively, continued operation is allowed if the air cooler unit condensate measuring system is OPERABLE, provided grab samples are taken or water inventory balance performed every 24 hours.

The 24 hour interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

C.1 and C.2

With the required containment fan cooler unit condensate measuring system inoperable, alternative action is again required. Either SR 3.4.15.1 must be performed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information. Provided a CHANNEL CHECK is performed every 8 hours or a water inventory balance is performed every 24 hours, reactor operation may continue while awaiting restoration of the containment fan cooler unit condensate measuring system to OPERABLE status.

The 24 hour interval provides periodic information that is adequate to detect RCS LEAKAGE.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

With the required containment atmosphere radioactivity monitor and the required containment fan cooler unit condensate measuring system inoperable, the only means of detecting leakage is the containment sump flow monitor. This Condition does not provide the required diverse means of leakage detection. The Required Action is to restore either of the inoperable required monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a reduced configuration for a lengthy time period.

E.1 and E.2

If a Required Action of Condition A, B, C, or D cannot be met, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 3). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 3, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action E.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

(continued)

BASES

ACTIONS (continued)

F.1

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

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.15.2

SR 3.4.15.2 requires the performance of a COT on the required containment atmosphere radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 92 days considers instrument reliability, and operating experience has shown that it is proper for detecting degradation.

SR 3.4.15.3, SR 3.4.15.4 and SR 3.4.15.5

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 24 months is a typical refueling cycle and considers channel reliability. Again, operating experience has proven that this Frequency is acceptable.

REFERENCES

1. 10 CFR 50, Appendix A, Section IV, GDC 30.
2. FSAR, Section 6.
3. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose that an individual at the exclusion area boundary can receive for 2 hours following an accident, or at the low population zone outer boundary for the radiological release duration, is specified in 10 CFR 50.67 (Ref. 1). Doses to control room operators must be limited per GDC 19. The limits on specific activity ensure that the offsite and control room doses are appropriately limited during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the dose consequences in the event of a steam line break (SLB) or steam generator tube rupture (SGTR) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133. The allowable levels are intended to ensure that offsite and control room doses meet the appropriate acceptance criteria in the Standard Review Plan (Ref. 2).

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensure that the resulting offsite and control room doses meet the appropriate SRP acceptance criteria following a SLB or SGTR accident. The safety analyses (Refs. 3 and 4) assume the specific activity of the reactor coolant is at the LCO limits, and an existing reactor coolant steam generator (SG) tube leakage rate of 1 gpm exists. The safety analyses assume the specific activity of the secondary coolant is at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.18, "Secondary Specific Activity."

The analyses for the SLB and SGTR accidents establish the acceptance limits for RCS specific activity. Reference to these analyses is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

The safety analyses consider two cases of reactor coolant iodine specific activity. One case assumes specific activity at 1.0 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the rate of release of iodine from the fuel rods containing cladding defects to the primary coolant immediately after a SLB (by a factor of 500), or SGTR (by a factor of 335), respectively. The second case assumes the initial reactor coolant iodine activity at 60.0 μCi/gm DOSE EQUIVALENT I-131 due to an iodine spike caused by a reactor or an RCS transient prior

BASES

APPLICABLE SAFETY ANALYSES (continued)

to the accident. In both cases, the noble gas specific activity is assumed to be 652 μCi/gm DOSE EQUIVALENT XE-133.

The SGTR analysis also assumes a loss of offsite power at the same time as the reactor trip. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature ΔT signal.

The loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG power operated relief valves and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the Residual Heat Removal (RHR) system is placed in service.

The SLB radiological analysis assumes that offsite power is lost at the same time as the pipe break occurs outside containment. Reactor trip occurs after the generation of an SI signal on low steam line pressure. The affected SG blows down completely and steam is vented directly to the atmosphere. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the RHR system is placed in service.

Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed 60.0 μCi/gm for more than 48 hours.

The limits on RCS specific activity are also used for establishing standardization in radiation shielding and plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The iodine specific activity in the reactor coolant is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the noble gas specific activity in the reactor coolant is limited to 652 μCi/gm DOSE EQUIVALENT XE-133. The limits on specific activity ensure that offsite and control room doses will meet the appropriate SRP acceptance criteria (Ref. 2).

The SLB and SGTR accident analyses (Refs. 3 and 4) show that the calculated doses are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of a SLB or SGTR, lead to doses that exceed the SRP acceptance criteria (Ref. 2).

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, operation within the LCO limits for DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 is necessary to limit the potential consequences of a SLB or SGTR to within the SRP acceptance criteria (Ref. 2).

In MODES 5 and 6, the steam generators are not being used for decay heat removal, the RCS and steam generators are depressurized, and primary to secondary leakage is minimal. Therefore, the monitoring of RCS specific activity is not required.

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the specific activity is $\leq$ 60.0 μCi/gm. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is continued every 4 hours to provide a trend.

The DOSE EQUIVALENT I-131 must be restored to within limit within 48 hours. The Completion Time of 48 hours is acceptable since it is expected that, if there were an iodine spike, the normal coolant iodine concentration would be restored within this time period. Also, there is a low probability of a SLB or SGTR occurring during this time period.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S), relying on Required Actions A.1 and A.2 while the DOSE EQUIVALENT I-131 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient-specific activity excursions while the plant remains at, or proceeds to, power operation.

B.1

With the DOSE EQUIVALENT XE-133 greater than the LCO limit, DOSE EQUIVALENT XE-133 must be restored to within limit within 48 hours. The allowed Completion Time of 48 hours is acceptable since it is expected that, if there were a noble gas spike, the normal coolant noble gas concentration would be restored within this time period. Also, there is a low probability of a SLB or SGTR occurring during this time period.

BASES

ACTIONS (continued)

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODES(S), relying on Required Action B.1 while the DOSE EQUIVALENT XE-133 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient-specific activity excursions while the plant remains at, or proceeds to, power operation.

C.1 and C.2

If the Required Action and associated Completion Time of Condition A or B is not met, or if the DOSE EQUIVALENT I-131 is > 60.0 μCi/gm, the reactor must be brought to MODE 3 within 6 hours and MODE 5 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 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the noble gas specific activity of the reactor coolant at least once every 7 days. This measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in the noble gas specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The 7 day Frequency considers the low probability of a gross fuel failure during this time.

Due to the inherent difficulty in detecting Kr-85 in a reactor coolant sample due to masking from radioisotopes with similar decay energies, such as F-18 and I-134, it is acceptable to include the minimum detectable activity for Kr-85 in the SR 3.4.16.1 calculation. If a specific noble gas nuclide listed in the definition of DOSE EQUIVALENT XE-133 is not detected, it should be assumed to be present at the minimum detectable activity.

A Note modifies the SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.16.2

This Surveillance is performed to ensure iodine specific activity remains within the LCO limit during normal operation and following fast power changes when iodine spiking is more apt to occur. The 14 day Frequency is adequate to trend changes in the iodine activity level, considering noble gas activity is monitored every 7 days. The Frequency, between 2 and 6 hours after a power change $\geq$ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following iodine spike initiation; samples at other times would provide inaccurate results.

The Note modifies this SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1.

REFERENCES

1. 10 CFR 50.67.

2. Standard Review Plan (SRP) Section 15.0.1 "Radiological Consequence Analyses Using Alternative Source Terms."

3. FSAR, Section 14.2.4.

4. FSAR, Section 14.2.5.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops – MODES 1 and 2," LCO 3.4.5, "RCS Loops – MODE 3," LCO 3.4.6, "RCS Loops – MODE 4," and LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled."

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 5.5.8, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.8, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.8.

BASES

BACKGROUND (continued)

Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.
The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to the operational LEAKAGE rate limits in LCO 3.4.13, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes the contaminated secondary fluid is released to the atmosphere via SG safety valves or atmospheric relief valves.

The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture.) In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 1 gallon per minute or is assumed to increase to 1 gallon per minute as a result of accident induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, "RCS Specific Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the applicable limits of 10 CFR 50.67 (Ref. 2) and Regulatory Guide 1.183 (Ref. 3).

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)2)(ii).

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the plugging criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. If a tube was determined to satisfy the plugging criteria but was not plugged, the tube may still have tube integrity.

BASES

LCO (continued)

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall between the tube-to-tubesheet weld as the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.8, “Steam Generator Program,” and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to met the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, “The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation.” Tube collapse is defined as, “For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero.” The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term “significant” is defined as “An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established.” For tube integrity evaluations, except for circumferential degradations, axial thermal loads are

BASES

LCO (continued)

classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 0.3 gpm per SG and 1 gpm through all SGs. The accident induced leakage rate includes any primary to secondary LEAKAGE existing prior to the accident in addition to primary to secondary LEAKAGE induced during the accident.

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in LCO 3.4.13, “RCS Operational LEAKAGE,” and limits primary to secondary LEAKAGE through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

BASES

APPLICABILITY (continued)

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

A.1 and A.2

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube plugging criteria but were not plugged in accordance with the Steam Generator Program as required by SR 3.4.17.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG plugging criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling out age or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

A Completion Time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity.

BASES

ACTIONS (continued)

A.1 and A.2 (continued)

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the “as found” condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.17.1 (continued)

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube plugging criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.17.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.8 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections. If crack indications are found in any SG tube, the maximum inspection interval for all affected and potentially affected SGs is restricted by Specification 5.5.8 until subsequent inspections support extending the inspection interval.

SR 3.4.17.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. The tube plugging criteria delineated in Specification 5.5.8 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube plugging criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.17.2 (continued)

The Frequency of prior to entering MODE 4 following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the plugging criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

REFERENCES

1. NEI 97-06, “Steam Generator Program Guidelines.”

2. 10 CFR 50. 67.

3. Regulatory Guide 1.183, “Alternate Radiological Source Terms for Evaluating Design Basis Accidents in Nuclear Power Reactors”, July 2000.

4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.

5. Draft Regulatory Guide 1.121, “Basis for Plugging Degraded Steam Generator Tubes,” August 1976.

6. EPRI, “Pressurized Water Reactor Steam Generator Examination Guidelines.”

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are to supply water to the reactor vessel during the blowdown phase of a loss of coolant accident (LOCA), to provide inventory to help accomplish the refill phase that follows thereafter, and to provide Reactor Coolant System (RCS) makeup for any LOCA that reduces RCS pressure to below the accumulator pressure.

The blowdown phase of a large break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The blowdown phase of the transient ends when the RCS pressure falls to a value approaching that of the containment atmosphere.

In the refill phase of a LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The balance of accumulator inventory is then available to help fill voids in the lower plenum and reactor vessel downcomer so as to establish a recovery level at the bottom of the core and ongoing reflood of the core with the addition of safety injection (SI) water.

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required in order for them to perform their function. Internal accumulator tank pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the accumulator pressure.

Each accumulator is piped into an RCS cold leg via an accumulator line and is isolated from the RCS by a motor operated isolation valve and two check valves in series.

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BASES

BACKGROUND (continued)

The accumulator size, water volume, and nitrogen cover pressure are selected so that three of the four accumulators are sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that three accumulators are adequate for this function is consistent with the LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of the LOCA.

APPLICABLE SAFETY ANALYSES

The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (Ref. 1). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of ECCS flow. In the early stages of a LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is required by regulations and conservatively imposes a delay wherein the ECCS pumps cannot deliver flow until the emergency diesel generators start, come to rated speed, and go through their timed loading sequence. In cold leg break scenarios, the entire contents of one accumulator are assumed to be lost through the break.

The limiting large break LOCA is a double ended guillotine break at the discharge of the reactor coolant pump. During this event, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure.

As a conservative estimate, no credit is taken for ECCS pump flow until an effective delay has elapsed. This delay accounts for the diesels starting and the pumps being loaded and delivering full flow. The delay time is conservatively set with an additional 2 seconds to account for SI signal generation. During this time,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the accumulators are analyzed as providing the sole source of emergency core cooling. No operator action is assumed during the blowdown stage of a large break LOCA.

The worst case small break LOCA analyses also assume a time delay before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated solely by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and high head safety injection (HHSI) pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the HHSI pumps become solely responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 2) will be met following a LOCA:

a. Maximum fuel element cladding temperature is $\leq$ 2200^{0}F;

b. Maximum cladding oxidation is $\leq$ 0.17 times the total cladding thickness before oxidation;

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

d. Core is maintained in a coolable geometry.

Since the accumulators discharge during the blowdown phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

For both the large and small break LOCA analyses, a nominal contained accumulator water volume is used. The contained water volume is the same as the deliverable volume for the accumulators, since the accumulators are emptied, once discharged.

Accumulator tank size and accumulator water volume directly affect the volume of nitrogen cover gas whose expansion produces the passive injection and thus affects injection rate. The amount of water is also important since the accumulator water which has not been injected and bypassed during blowdown is primarily responsible for filling the lower plenum (refill) and downcomer. The elevation head of the downcomer water provides the driving force for core reflooding (Ref. 3).

For large break LOCAs, changes in accumulator water volume can result in either improved or worsened analysis results; therefore, a nominal accumulator water volume of 795 cubic feet is modeled in the analysis (Ref. 3).

For small break LOCAs, changes in accumulator water volume are not significant because the clad temperature transient is terminated before the accumulators empty; therefore, a nominal accumulator water volume of 795 cubic feet is modeled in the analysis (Ref. 3).

The minimum boron concentration setpoint is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction in the accumulator minimum boron concentration would produce a subsequent reduction in the available containment sump concentration for post LOCA shutdown and an increase in the maximum sump pH. The maximum boron concentration is used in determining the cold leg to hot leg recirculation injection switchover time and minimum sump pH.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The large and small break LOCA analyses are performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. The maximum nitrogen cover pressure limit prevents injection of nitrogen into the RCS, accumulator relief valve actuation, and ultimately preserves accumulator integrity.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 3 and 4).

The accumulators satisfy Criterion 3 of 10 CFR 50.36.

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Four accumulators are required to ensure that 100% of the contents of three of the accumulators will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than three accumulators are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 2) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above 2000 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure must be met.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that the

(continued)

BASES

APPLICABILITY (continued)

ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 2) limit of 2200°F.

In MODE 3, with RCS pressure $\leq$ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated discharge isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

Note 1 provides an exception to SR 3.5.1.1 and SR 3.5.1.5 and specifies that all accumulator discharge isolation valves may be closed and energized for up to 8 hours during the performance of reactor coolant system hydrostatic testing. This allowance is necessary because limits imposed by the Pressure/Temperature Limits for a hydrostatic leak test, could, in some instances, require reactor coolant system hydrostatic testing above 350°F (Mode 3). This allowance is acceptable because hydrostatic testing is performed in MODE 3 when the need for the accumulators is reduced and Note 1 limits the duration to the time needed to perform required testing.

Note 2 also provides an exception to SR 3.5.1.1 and SR 3.5.1.5 and specifies that one accumulator discharge isolation valve may be closed and energized in MODE 3 for up to 8 hours for accumulator check valve leakage testing. This allowance is acceptable because testing is limited to MODE 3 when the need for the accumulators is reduced and Note 2 limits the duration to the time needed to perform required testing.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of

(continued)

BASES

ACTIONS

A.1 (continued)

the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis techniques demonstrate that the accumulators do not discharge following a large main steam line break. Even if they do discharge, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 24 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is justified in WCAP-15049-A, Rev. 1 (Ref. 4).

C.1 and C.2

If the accumulator cannot be returned 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 MODE 3 within 6 hours and reactor coolant pressure reduced to $\leq$ 1000 psig within 12 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.

(continued)

BASES

ACTIONS (continued)

D.1

If more than one accumulator is inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator valve should be verified to be fully open every 12 hours. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. If a discharge isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a closed valve could result in not meeting accident analyses assumptions. This Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned isolation valve is unlikely.

SR 3.5.1.2 and SR 3.5.1.3

Every 12 hours, borated water volume and nitrogen cover pressure are verified for each accumulator. This Frequency is sufficient to ensure adequate injection during a LOCA. Because of the static design of the accumulator, a 12 hour Frequency usually allows the operator to identify changes before limits are reached. Operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator every 31 days since the static design of the accumulators limits the ways in which the concentration can be changed. The 31 day Frequency is adequate to identify changes that could occur from mechanisms such as stratification or

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.4 (continued)

inleakage. Sampling the affected accumulator within 6 hours after an increase of 8.4 cubic feet will identify whether inleakage has caused a reduction in boron concentration to below the required limit. Considering the nominal accumulator volume of 795 cubic feet of water, inleakage of 8.4 cubic feet of pure water would result in a boron concentration reduction of approximately 1%. An increase in the accumulator volume of 8.4 cubic feet causes a change of approximately 10% in the indicated accumulator level. It is not necessary to verify boron concentration if the added water inventory is from the refueling water storage tank (RWST), because the water contained in the RWST is within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 5).

SR 3.5.1.5

Verification every 31 days that power is removed from each accumulator discharge isolation valve operator when the reactor coolant system pressure is $\geq$ 2000 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only two accumulators would be available for injection given a single failure coincident with a LOCA. Since power is removed under administrative control, the 31 day Frequency will provide adequate assurance that power is removed.

This SR allows power to be supplied to the motor operated discharge isolation valves when reactor coolant system pressure is < 2000 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns. Should closure of a valve occur, the SI signal provided to the valves would open a closed valve in the event of a LOCA.

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BASES

REFERENCES

1. FSAR, Chapter 6.
2. 10 CFR 50.46.
3. FSAR, Chapter 14.
4. WCAP-15049-A, Rev. 1, April 1999.
5. NUREG-1366, February 1990.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS — Operating

BASES

BACKGROUND

The function of the ECCS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents:

a. Loss of coolant accident (LOCA), coolant leakage greater than the capability of the normal charging system;

b. Rod ejection accident;

c. Loss of secondary coolant accident; and

d. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power.

There are three phases of ECCS operation: injection, cold leg recirculation, and hot leg recirculation. In the injection phase, water is taken from the refueling water storage tank (RWST) and injected into the Reactor Coolant System (RCS) through the cold legs. When sufficient water is removed from the RWST to ensure that enough boron has been added to maintain the reactor subcritical and the recirculation and containment sumps have enough water to supply the required net positive suction head to the ECCS pumps, suction is switched to the recirculation sump for cold leg recirculation. After 6.5 hours, the ECCS flow is shifted to the hot leg recirculation phase to provide a backflush, which would reduce the boiling in the top of the core and any resulting boron precipitation.

(continued)

BACKGROUND (continued)

The ECCS FUNCTION is provided by three separate ECCS systems: high head safety injection (HHSI), residual heat removal (RHR) injection, and containment recirculation. Each ECCS system is divided into subsystems as follows:

- HHSI System is divided into three 50% capacity subsystems (i.e., HHSI 31, 32 and 33) which share two pump discharge headers (i.e., 31 and 33). Each HHSI subsystem consists of one pump as well as associated piping and valves to transfer water from the suction source to the core. HHSI subsystem 32 is aligned to inject using the flow path associated with both HHSI subsystem 31 and 33. If either HHSI pump 31 or 33 fails to start or achieve required discharge pressure, HHSI pump 32 will inject via the header associated with the failed pump. If all three HHSI pumps start, flow from HHSI pump 32 will be divided between header 31 and 33. Note that the HHSI pumps have a shutoff head of approximately 1500 psig. Therefore, IP3 is classified as a low head safety injection plant.

- RHR injection System is divided into two 100% capacity subsystems. Each ECCS RHR subsystem consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either RHR subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR injection subsystem.

- Containment Recirculation is divided into two 100% capacity subsystems. Each subsystem consists of one Containment Recirculation pump and one RHR heat exchanger as well as associated piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either Recirculation subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE Containment Recirculation subsystem.

(continued)

BASES

BACKGROUND (continued)

- The three ECCS systems (3 HHSI, 2 RHR and 2 Recirculation) are grouped into three trains (5A, 2A/3A and 6A) such that any 2 of the 3 trains are capable of meeting all ECCS capability assumed in the accident analysis. Each ECCS train consists of the following:

  a. ECCS Train 5A includes subsystems HHSI 31 and containment recirculation 31;

  b. ECCS Train 2A/3A includes subsystems HHSI 32 and RHR 31; and,

  c. ECCS Train 6A includes subsystems HHSI 33, RHR 32, and containment recirculation 32.

The ECCS trains use the same designation as the Safeguards Power Trains required by LCO 3.8.9, Distribution Systems - Operating, with Safeguards Power Train 5A supported by DG 33, Safeguards Power Train 2A/23 supported by DG 31, Safeguards Power Train 6A supported by DG 32.

The ECCS accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the RWST can be injected into the RCS following the accidents described in this LCO. The major components of each subsystem are the high head safety injection pumps, the RHR pumps, heat exchangers, and the containment recirculation pumps. This interconnecting and redundant subsystem design provides the operators with the ability to utilize components from different trains to achieve the required 100% flow to the core.

During the injection phase of LOCA recovery, a suction header supplies water from the RWST to the HHSI and RHR pumps. The discharge from the HHSI and RHR pumps feed injection lines to each of the RCS cold legs. Control valves are set to balance the HHSI flow to the RCS.

This balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs.

(continued)

BASES

BACKGROUND (continued)

During the recirculation phase of LOCA recovery, the containment recirculation pumps take suction from the containment recirculation sump and direct flow through the RHR heat exchangers to the cold legs. The RHR pumps can be used to provide a backup method of recirculation in which case the RHR pump suction is transferred to the containment sump. The RHR pumps then supply recirculation flow directly or supply the suction of the HHSI pumps. Initially, recirculation is through the same paths as the injection phase. Subsequently, recirculation injection is split between the hot and cold legs.

The ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

During low temperature conditions in the RCS, limitations are placed on the maximum number of HHSI pumps that may be OPERABLE. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for the basis of these requirements.

The ECCS subsystems, except for the containment recirculation subsystems, are actuated upon receipt of an SI signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately in the programmed sequence. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the emergency diesel generators (EDGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet GDC 35 (Ref. 1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 2), will be met following a LOCA:

a. Maximum fuel element cladding temperature is $\leq 2200^{o}F$;

b. Maximum cladding oxidation is $\leq$ 0.17 times the total cladding thickness before oxidation;

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

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following an MSLB event.

Each ECCS subsystem is taken credit for in a large break LOCA event at full power (Refs. 3 and 4). This event establishes the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The HHSI pumps are credited in a small break LOCA event. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with loss of offsite power and a single failure disabling one EDG; and

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one EDG.

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion for small breaks. Following depressurization, emergency cooling water is injected into the cold legs, flows into the downcomer, fills the lower plenum, and refloods the core.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The effects on containment mass and energy releases are accounted for in appropriate analyses (Refs. 3 and 4). The LCO ensures that an ECCS train will deliver sufficient water to match boiloff rates soon enough to minimize the consequences of the core being uncovered following a large LOCA. It also ensures that the HHSI pumps will deliver sufficient water and boron during a small LOCA to maintain core subcriticality. For a small break LOCA, the steam generators continue to serve as the heat sink, providing part of the required core cooling.

The ECCS trains satisfy Criterion 3 of 10 CFR 50.36.

LCO

In MODES 1, 2, and 3, three ECCS trains are required to ensure that sufficient ECCS flow is available, assuming a single failure affecting any one train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents.

In MODES 1, 2, and 3, the ECCS consists of the following:

a. ECCS Train 5A includes HHSI subsystem 31 and containment recirculation subsystem 31;

b. ECCS Train 2A/3A includes HHSI subsystem 32 and RHR subsystem 31; and,

c. ECCS Train 6A includes HHSI subsystem 33, RHR subsystem 32, and containment recirculation subsystem 32.

Each HHSI subsystem consists of one pump as well as associated instrumentation, piping and valves to transfer water from the suction source to the core. HHSI subsystem 32 is OPERABLE when capable of injecting using the flow paths associated with HHSI subsystem 31 and 33. Each ECCS RHR subsystem consists of one RHR pump and one RHR heat exchanger as well as associated instrumentation, piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either RHR subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR injection subsystem.

(continued)

BASES

LCO (continued)

Each containment recirculation subsystem consists of one Containment Recirculation pump and one RHR heat exchanger as well as associated instrumentation piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either Recirculation subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE Containment Recirculation subsystem. Note that Recirculation pump OPERABILITY requires the functional availability of one of the two the associated auxiliary component cooling water pumps.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the HHSI and RHR pumps and their supply header to each of the four cold leg injection nozzles (6 cold leg injection nozzles for the HHSI pumps). Note: One of the four originally installed cold leg lines in each header has been isolated by a locked closed valve as part of a Stretch Power Uprate (SPU) modification to provide higher hot leg recirc flow and to support higher branch-line valve positions to minimize sump particle blockage and reduce potential for throttle valve cavitation). In the long term, this flow path may be switched to take its supply from the containment recirculation sump using the containment recirculation pumps or, as a backup, the containment sump using the RHR pumps to supply its flow to the RCS hot and cold legs, either directly into the RCS or via the HHSI pumps.

The flow path for each train must maintain its designed independence to ensure that no single failure can disable more than one ECCS train (except as described in Reference 5).

As indicated in Note 1, the SI flow paths may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. This is acceptable because the flow paths are readily restorable from the control room or the valves are opened under administrative controls that ensure prompt closure when required. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room.

As indicated in Note 2, operation in MODE 3 with ECCS trains made incapable of injecting pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is necessary for plants with an LTOP arming temperature at or near the MODE 3 boundary temperature of 350^{0}F. LCO 3.4.12 requires that certain pumps be made incapable of injecting at and below the LTOP arming temperature. When this temperature is at or near the MODE 3 boundary temperature, time is needed to restore the inoperable pumps to OPERABLE status.

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BASES

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements when at lower power. The HHSI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

This LCO is only applicable in MODE 3 and above. Below MODE 3, system functional requirements are relaxed as described in LCO 3.5.3, "ECCS – Shutdown."

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level."

ACTIONS

A.1

With one or more trains inoperable and any two HHSI pumps, any one RHR pump, and any one Containment Recirculation pump OPERABLE (i.e., 100% of the ECCS capability assumed in the accident analysis is available), the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 4) and is a reasonable time for repair of many ECCS components. If 100% of the ECCS capability assumed in the accident analysis is not OPERABLE, entry into LCO 3.0.3 is required.

An ECCS train is inoperable if it is not capable of delivering design flow to the RCS. Individual components are inoperable if they are not capable of performing their design function or supporting systems are not available.

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one pump in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different pumps, each in a different train, necessarily result in a

(continued

BASES

ACTIONS (continued)

A.1

loss of function for the ECCS. The intent of this Condition is to maintain a combination of equipment such that 100% of the ECCS flow equivalent to two OPERABLE ECCS trains remains available. This allows increased flexibility in plant operations under circumstances when pumps in redundant trains are inoperable.

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 4) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

Reference 5 describes situations in which one component, such as the valves governed by SR 3.5.2.1, can disable more than one ECCS train. With one or more component(s) inoperable such that 100% of the flow equivalent for HHSI, RHR and Containment Recirculation is not available, the facility is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

If the inoperable trains cannot be returned 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 MODE 3 within 6 hours and MODE 4 within 12 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.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render more than one ECCS train inoperable. Securing these valves in position by removal of power or by key locking the control in the correct position ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. These valves are of the type, described in Reference 5, that can disable the function of more than one ECCS train and invalidate the accident analyses. A 12 hour Frequency is considered reasonable in view of other administrative controls that will ensure a mispositioned valve is unlikely.

SR 3.5.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day Frequency is appropriate because the valves are operated under administrative control, and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.2.3

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.3

flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program of the ASME Code. The ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.4 and SR 3.5.2.5

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal and that each ECCS pump starts on receipt of an actual or simulated SI signal. Note that the Containment Recirculation system is a manually initiated system and is not included as part of this SR. Additionally, this Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned plant transients if the Surveillances were performed with the reactor at power. The 24 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program.

SR 3.5.2.6

Alignment of valves in the HHSI flow path is necessary for proper ECCS performance. These valves have stops to allow proper positioning and/or locking manual valve in the flow path for restricted flow to a ruptured cold leg, ensuring that the other cold legs receive at least the required minimum flow, and to allow proper positioning for restricting hot leg flow. Therefore, an improperly positioned valve could result in the inoperability of more than one injection flow path. The stops and/or the locked manual valves are set based on the results of the most recent ECCS operational flow test. Valves SI-856B, 856C, 856D, 856E, 856H, 856J, and 856K are not necessarily used for flow balancing but can be used to trim system resistance during flow balance testing. The stop positions are set to reflect their usage. The 24 month Frequency is based on the reasons stated in SR 3.5.2.4 and SR 3.5.2.5.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.7 (continued)

Periodic inspections of each containment and recirculation sump suction inlet ensure that each is unrestricted and stays in proper operating condition. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, on the need to have access to the location, and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. This Frequency is sufficient to detect abnormal degradation and is confirmed by industry operating experience.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 35.
2. 10 CFR 50.46.
3. FSAR, Section 14.
4. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
5. IE Information Notice No. 87-01.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS — Shutdown

BASES

BACKGROUND

The Background section for Bases 3.5.2,"ECCS — Operating," is applicable to these Bases, with the following modifications.

In MODE 4, two ECCS High Head Safety Injection (HHSI) subsystems and one ECCS residual heat removal (RHR) subsystem are required.

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the refueling water storage tank (RWST) or the containment sump can be injected into the Reactor Coolant System (RCS) following the accidents described in Bases 3.5.2.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of Bases 3.5.2 also applies to this Bases section.

Due to the stable conditions associated with operation in MODE 4 and the reduced probability of occurrence of a Design Basis Accident (DBA), the ECCS operational requirements are reduced. It is understood in these reductions that automatic safety injection (SI) actuation is not available. In this MODE, sufficient time exists for manual actuation of the required ECCS to mitigate the consequences of a DBA.

Only two ECCS HHSI subsystems (high head) and one ECCS residual heat removal (RHR) subsystem are required for MODE 4. This requirement dictates that single failures are not considered during this MODE of operation. The ECCS trains satisfy Criterion 3 of 10 CFR 50.36.

LCO

In MODE 4, two ECCS HHSI subsystems (high head) and one ECCS residual heat removal (RHR) subsystem are required to be OPERABLE to ensure that sufficient ECCS flow is available to the core following a DBA. Each required subsystem includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST and transferring suction to the containment sump. Either RHR heat exchanger may be used with either RHR pump to meet requirements for an RHR subsystem.

(continued)

BASES

LCO (continued)

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to each of the four cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to deliver its flow to the RCS hot and cold legs.

This LCO is modified by a Note that allows an RHR subsystem to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the ECCS mode of operation and not otherwise inoperable. This allows operation in the RHR mode during MODE 4. Similarly, this Note allows an RHR subsystem to be considered OPERABLE during alignment and operation for valve testing if capable of being manually realigned (remote or local) to the ECCS mode of operation and not otherwise inoperable. This allows testing of certain valves in MODE 4.

An HHSI subsystem is considered OPERABLE when injection capability is blocked to meet requirements of LCO 3.4.12, if capable of being manually realigned (remote or local) to the ECCS mode of operation and not otherwise inoperable. This allows injection capability to be blocked in MODE 4 if needed to satisfy the requirements of LCO 3.4.12, “Low Temperature Overpressure Protection (LTOP).”

APPLICABILITY

In MODES 1, 2, and 3, the OPERABILITY requirements for ECCS are covered by LCO 3.5.2. In MODE 4 with RCS temperature below 350 ^{0}F, two ECCS HHSI subsystems and one ECCS residual heat removal (RHR) subsystem are acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level."

(continued)

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to inoperable ECCS High Head Safety Injection (HHSI) subsystems when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS High Head Safety Injection subsystem and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to a loss of coolant accident or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the required cooling capacity. Normally, in MODE 4, reactor decay heat is removed from the RCS by an RHR loop. If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

With both RHR pumps and heat exchangers inoperable, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the RHR. With no ECCS HHSI subsystem OPERABLE, due to the inoperability of the pump or flow path from the RWST, the plant is not prepared to provide high pressure response to Design Basis Events requiring SI. Therefore, the appropriate action is to initiate measures to restore one ECCS RHR subsystem and two ECCS HHSI subsystems and to continue the actions until the subsystem is restored to OPERABLE status.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 2). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 2, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

BASES

ACTIONS (continued)

Required Action A.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases 3.5.2 apply.

REFERENCES

1. The applicable references from Bases 3.5.2 apply.

2. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Refueling Water Storage Tank (RWST)

BASES

BACKGROUND

The RWST supplies borated water to the Chemical and Volume Control System (CVCS) during abnormal operating conditions, to the refueling cavity during refueling, to the ECCS to fill accumulators, and to the ECCS and the Containment Spray System during accident conditions.

The RWST supplies the ECCS and the Containment Spray System through separate supply headers during the injection phase of a loss of coolant accident (LOCA). Motor operated isolation valves are provided to isolate the RWST from the ECCS subsystems once the system has been transferred to the recirculation mode. The switchover to the cold leg recirculation phase is manually initiated when the RWST level has reached the low-alarm setpoint and sufficient coolant inventory to support pump operation in recirculation mode is verified to be in the containment. Use of a single RWST to supply all of the injection trains of the ECCS and Containment Spray System is acceptable since the RWST is a passive component, and passive failures are not required to be assumed to occur coincidentally with Design Basis Events.

During normal operation in MODES 1, 2, and 3, the high head safety injection (HHSI) and residual heat removal (RHR) pumps are aligned to take suction from the RWST.

The ECCS and Containment Spray System pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at or near shutoff head conditions.

This LCO ensures that:

a. The RWST contains sufficient borated water to support the ECCS during the injection phase;

b. Sufficient water volume exists in the recirculation sump or the containment sump to support continued operation of the ECCS and Containment Spray System pumps at the time of transfer to the recirculation mode of cooling; and

c. The reactor remains subcritical following a LOCA or MSLB.

(continued)

BASES

BACKGROUND (continued)

Insufficient water in the RWST could result in insufficient cooling capacity when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of SDM or excessive boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment due to improper pH in the sumps.

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWST provides a source of borated water to the ECCS and Containment Spray System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS — Operating"; B 3.5.3, "ECCS — Shutdown"; and B 3.6.6, "Containment Spray System and Containment Fan Cooler System." These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the accident analyses.

The RWST must also meet volume, boron concentration, and temperature requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWST, the deliverable volume is different from the total volume contained since, due to the design of the tank, more water can be contained than can be delivered.

For a large break LOCA analysis, the minimum water volume limit of 195,800 gallons and the lower boron concentration limit of 2400 ppm are used to compute the post LOCA sump boron concentration necessary to assure subcriticality. The large break LOCA is the limiting case since the safety analysis assumes that all control rods are out of the core.

The RWST level required by Technical Specifications includes allowances for instrument accuracy, the unusable volume in the RWST, and the maximum volume expected to remain in the RWST when the plant is switched from the injection to recirculation modes of operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The upper limit on boron concentration of 2600 ppm is used to determine the maximum allowable time to switch to hot leg recirculation following a LOCA. The purpose of switching from cold leg to hot leg injection is to avoid boron precipitation in the core following the accident.

In the ECCS analysis, the containment spray temperature is assumed to be equal to the RWST lower temperature limit of 35 ^{0}F. If the lower temperature limit is violated, the containment spray further reduces containment pressure, which decreases the rate at which steam can be vented out the break and increases peak clad temperature. The upper temperature limit of 105^{0}F is used in the LOCA containment integrity analysis. Exceeding this temperature will result in higher containment pressures due to reduced containment spray cooling capacity. The minimum boron concentration is an explicit assumption in the main steam line break (MSLB) analysis to ensure the required shutdown capability. For the containment response following an MSLB, the lower limit on boron concentration and the upper limit on RWST water temperature are used to maximize the total energy release to containment.

Following a LOCA, switchover from the injection phase to the recircuation phase must occur before the RWST empties to prevent damage to the pumps and a loss of cooling capability. For similar reasons, switchover must not occur before there is sufficient water in the containment to support recirculation pump suction. Furthermore, early switchover must not occur to ensure that sufficient borated water is injected from the RWST.

The IP3 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low level in the RWST coincident with a safety injection signal. This function is performed manually by the operator who must be alerted by redundant RWST low level alarms. The switchover to the cold leg recirculation phase is manually initiated when the RWST level has reached the low alarm setpoint and sufficient coolant inventory to support pump operation in recirculation mode is verified to be in the containment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The RWST low level alarm setpoint has both upper and lower limits. The upper limit is set to ensure that switchover does not occur until there is adequate water inventory in the containment to provide ECCS pump suction. (This is confirmed by recirculation and/or containment sump level indication.) The lower limit is set to ensure switchover occurs before the RWST empties, to prevent ECCS pump damage.

Requiring 2 channels of RWST low level alarm ensures that the alarm function will be available assuming a single failure of one channel.

The RWST satisfies Criterion 3 of 10 CFR 50.36.

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level in the recirculation sump and the containment sump to support ECCS pump operation in the recirculation mode.

To be considered OPERABLE, the RWST must meet the water level, boron concentration, and temperature limits established in the SRs.

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and Containment Spray System OPERABILITY requirements. Since both the ECCS and the Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level."

(continued)

BASES

APPLICABILITY (continued)

A note allows the RWST valves AC-727A, AC-727B and AC-725 that isolate non seismic piping to be opened under administrative control until the end of RO 18. The administrative controls will require a designated operator to be assigned to isolate the RWST as needed. The operator will be trained on when to isolate in accordance with required procedure (e.g., specific indications of SI, loss of offsite power, CR orders) and that this is a critical function to be performed as quickly as possible. The operator will coordinate with the CR if leaving the PAB for activities such as shift turnover. The operator shall discuss the functions to be performed when turning over to a designated operator during shift change. The controls are sufficient to assure that the TS required amount of water will be available under all conditions.

ACTIONS

A.1

With RWST boron concentration or borated water temperature not within limits of SR 3.5.4.3 and SR 3.5.4.1, respectively, they must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE condition. The 8 hour limit to restore the RWST temperature or boron concentration to within limits was developed considering the time required to change either the boron concentration or temperature and the fact that the contents of the tank are still available for injection.

B.1

Condition B applies when one channel of RWST low level alarm is inoperable. Required Action B.1 requires restoring the inoperable channel to OPERABLE status within 7 days. The 7 day Completion Time for restoration of redundancy to the alarm function is needed because the IP3 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low level in the RWST coincident with a safety injection signal. This function is performed manually by the operator who is alerted by the RWST low level alarm as the primary indicator for determining the time for the switchover. The 7 day Completion Time for restoration of redundancy for this alarm function is acceptable because of the remaining alarm channel and the availability of containment and recirculation sump level indication in the containment.

(continued)

BASES

ACTIONS (continued)

C.1

With the RWST inoperable for reasons other than Condition A (e.g., water volume) or B (e.g., two level alarms inoperable), it must be restored to OPERABLE status within 1 hour.

In this Condition, neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

D.1 and D.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 2). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 2, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action D.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified every 24 hours to be within the limits assumed in the accident analyses band. This Frequency is sufficient to identify a temperature change that would approach either limit and has been shown to be acceptable through operating experience.

The SR is modified by a Note that eliminates the requirement to perform this Surveillance when ambient air temperatures are within the operating limits of the RWST (a reduced temperature is used to assure restrictions on allowable Containment operating pressures are met) and the heating steam isolation valves are locked closed. With ambient air temperatures within the band, the RWST temperature should not exceed the limits.

SR 3.5.4.2

The RWST water volume should be verified every 7 days to be above the required minimum level in order to ensure that a sufficient initial supply is available for injection and to support continued ECCS System pump operation on recirculation.

Since the RWST volume is normally stable and is protected by an alarm, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience.

SR 3.5.4.3

The boron concentration of the RWST should be verified every 31 days to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. Since the RWST level is normally stable, a 31 day sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

SR 3.5.4.4

Performance of the CHANNEL CHECK every 7 days ensures that a gross failure of the RWST level instruments has not occurred. A CHANNEL CHECK is normally the comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same channel

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.4.4 (continued)

should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure: thus, it is key to verifying that the RWST level instruments continue to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the RWST level instrument channel has drifted outside the limit. If the channels are within criteria, it is an indication that the RWST level instrument channels are OPERABLE.

The frequency of 7 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of displays associated with the LCO required RWST level instruments.

SR 3.5.4.5

A CHANNEL CALIBRATION of the RWST level switch is performed at least every 184 days. CHANNEL CALIBRATION is a complete check of the level switch loop including the required alarm. The test verifies the RWST level switch responds to RWST level within the required range and accuracy. The test also verifies that the RWST level switch will cause the low level alarm to annunciate at ≥10.5 feet and ≤12.5 feet to ensure the operator is alerted to start the switchover to the recirculation mode during accident conditions. The frequency is based on operating experience and previous license commitments.

SR 3.5.4.6

A CHANNEL CALIBRATION of the RWST level transmitter is performed at least every 18 months. CHANNEL CALIBRATION is a complete check of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.4.6 (continued)

the RWST level transmitter loop including the required alarm. The test verifies the RWST level transmitter responds to RWST level within the required range and accuracy.

The test also verifies that the RWST level transmitter will cause the low level alarm to annunciate at ≥10.5 feet and ≤12.5 feet to ensure the operator is alerted to start the switchover to the recirculation mode during accident conditions. The frequency is based on operating experience and previous license commitments.

REFERENCES

1. FSAR, Chapter 6 and Chapter 14.
2. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment consists of the concrete reactor building, its steel liner, and the penetrations through this structure. The structure is designed to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA), in particular, a Main Steam Line Break (MSLB) inside containment or a Loss of Coolant Accident (LOCA). Additionally, this structure provides shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment is a reinforced concrete structure with a cylindrical wall, a flat foundation mat, and a dome roof. The inside surface of the containment is lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions.

The concrete reactor building is required for structural integrity of the containment under DBA conditions. The steel liner and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B, (Ref. 1), as modified by approved exemptions.

The isolation devices for the penetrations in the containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

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

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

(continued)

BASES

BACKGROUND (continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves";

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. The equipment hatch is properly closed; and

d. The Isolation Valve Seal Water (IVSW) system is OPERABLE, except as provided in LCO 3.6.9.

e. The Weld Channel and Penetration Pressurization System is OPERABLE, except as provided in LCO 3.6.10.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA) and a steam line break (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.1% of containment air weight per day assuming the proper functioning of the Isolation Valve Seal Water System but without benefit of the Weld Channel and Penetration Pressurization System (Ref. 3). This leakage rate, used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting DBAs (LBLOCA or MSLB). The

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.1% of containment air weight per day in the safety analysis at P_a which is specified in Specification 5.5.15, Containment Leakage Rate Testing Program.

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of 10 CFR 50.36.

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required leakage test in accordance with requirements in Specification 5.5.15, Containment Leakage Rate Testing Program. At this time, the applicable leakage limits specified in the Containment Leakage Rate Testing Program must be met.

Compliance with this LCO will ensure a containment configuration, including the equipment hatch, that is structurally sound and that will limit leakage to less than the leakage rates assumed in the safety analysis.

Individual leakage rates specified for the containment air locks (LCO 3.6.2) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J, Option B. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of $1.0\ L_a$.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES.

(continued)

BASES

APPLICABILITY (continued)

Therefore, containment is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The requirements for containment during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

A.1

In the event containment is inoperable, containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

B.1 and B.2

If 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 6 hours and to MODE 5 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 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock leakage limits specified in LCO 3.6.2 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

startup after performing the Containment Leakage Rate Testing Program 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. SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. FSAR, Chapter 14.
3. FSAR, Chapter 6.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is a cylinder with a door at each end. One of the two air locks is designed as a part of the containment structure and the other is designed as an integral part of the containment equipment hatch but otherwise the two air locks function identically. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY.

Each air lock door and the equipment hatch is designed with double gasketed seals to permit pressurization between the gaskets. The double gasketed seals are normally continuously pressurized above accident pressure. Finally, to effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door) and local leakage rate testing capability is available to ensure containment integrity is being maintained.

The doors are interlocked to prevent simultaneous opening of the inner and outer door. This interlock is a requirement for OPERABILITY. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary.

Each personnel air lock is provided with limit switches on both doors that provide control room indication when an airlock door is not fully closed.

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BASES

BACKGROUND (continued)

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analyses.

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident. In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.1% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a = 0.1% of containment air weight per day, the maximum allowable containment leakage rate at the calculated peak containment internal pressure P_a = 42.38 psig following a DBA (LBLOCA or MSLB). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of 10 CFR 50.36.

LCO

Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not

(continued)

BASES

LCO (continued)

exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

The program established by Specification 5.15, “Containment Leakage Rate Test Program,” which conforms to NEI 94-01, Section 10.2.2 (Ref. 3) for Containment Air Locks, requires that air lock doors opened during periods when containment integrity is required must be tested within 7 days after being opened. For Indian Point 3, which has air locks with testable seals, this requirement is satisfied in accordance with ANSI/ANS-56.8-1994 "Containment System Leakage Testing Requirements," (Ref. 4) by testing the seals (i.e., verifying that seals re-pressurize to the required pressure after an airlock door is closed). Pressurization of air lock seals is not required for air lock OPERABILITY except as needed to satisfy testing requirements after being opened.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by a Note that allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. When the inner door is inoperable, it is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment

(continued)

BASES

ACTIONS (continued)

boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed. If ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

In the event the air lock leakage results in exceeding the overall containment leakage rate, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Containment."

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

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

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ACTIONS

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

Required Action A.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door. This 7 day restriction begins when the second air lock is discovered inoperable. Containment entry may be required on a periodic basis to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-required activities) if the containment is entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time that the OPERABLE door is expected to be open.

(continued)

BASES

ACTIONS (continued)

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

With an air lock interlock mechanism inoperable in one or more air locks, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1, C.2, and C.3

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

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ACTIONS

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

Required Action C.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour Completion Time unless Condition C is exited in accordance with LCO 3.0.2 (i.e., one door is made OPERABLE). The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock.

D.1 and D.2

If the inoperable containment air lock 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 6 hours and to MODE 5 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 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of 10 CFR 50, Appendix J (Ref. 1), required by Specification 5.5.15, Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and containment

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1 (continued)

OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by Specification 5.5.15, Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria that is applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

SR 3.6.2.2

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the containment air lock door is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under conditions that apply during a plant outage, and the potential

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.2 (continued)

for loss of containment OPERABILITY if the Surveillance were performed with the reactor at power. The 24 month Frequency for the interlock is justified based on generic operating experience. The Frequency is based on engineering judgment and is considered adequate given that the interlock is not normally challenged during the use of the airlock.

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. FSAR, Section 6.6.
3. NEI 94-01, Section 10.2.2.
4. ANSI/ANS-56.8-1994, "Containment System Leakage Testing Requirements."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

Automatic isolation signals are produced during accident conditions. Containment Phase "A" isolation occurs upon receipt of a safety injection signal. The Phase "A" isolation signal isolates nonessential process lines in order to minimize leakage of fission product radioactivity. Containment Phase "B" isolation occurs upon receipt of a containment pressure High-High signal and isolates the remaining process lines, except systems required for accident mitigation. In addition to the isolation signals listed above, the Containment purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief isolation valves (PCV-1190, PCV-1191, and PCV-1192) close when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12). Containment purge and containment pressure relief are also isolated when high radiation levels are detected in the plant vent. As a result, the

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BASES

BACKGROUND (continued)

containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

Containment Purge System (36 inch purge valves)

The Containment Purge System, consisting of purge supply and exhaust isolation valves FCV-1170, FCV-1171, FCV-1172, and FCV-1173, operates to supply outside air into the containment for ventilation and cooling or heating and may also be used to reduce the concentration of noble gases within containment prior to and during personnel access. The supply and exhaust lines each contain two isolation valves. Because of their large size, the 36 inch purge valves are not qualified for automatic closure from their open position under DBA conditions. Therefore, the 36 inch purge valves must be maintained sealed closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Containment Pressure Relief Line (10 inch valves)

The Containment Pressure Relief Line consisting of pressure relief isolation valves PCV-1190, PCV-1191, and PCV-1192, operates to:

a. Reduce the concentration of noble gases within containment prior to and during personnel access, and

b. Equalize internal and external pressures.

Since the valves used in the Containment Pressure Relief Line are designed to meet the requirements for automatic containment isolation valves, these valves may be opened as needed in MODES 1, 2, 3, and 4. Containment pressure relief line

(continued)

BASES

BACKGROUND (continued)

isolation valve opening is limited by mechanical stops so that opening angle is limited to an angle at which analysis indicates the valve will operate against containment accident pressures. Additionally, pressure relief isolation valve opening must be limited to the time necessary for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open.

The containment pressure relief line is isolated during CORE ALTERATIONS and movement of irradiated fuel inside containment in accordance with requirements established in LCO 3.9.3, Containment Penetrations.

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

The DBA that results in a release of radioactive material within containment is a loss of coolant accident (LOCA) (Ref. 1). In the analyses for this accident, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves are minimized. The safety analyses assume that the 36 inch purge valves are sealed closed at event initiation.

The DBA analysis assumes that, within 60 seconds after the accident, isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a. The containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and containment isolation valve stroke times.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) may be unable to close in the environment following a LOCA. Therefore, each of the purge valves is required to remain sealed closed during MODES 1, 2, 3, and 4. In this case, the single failure criterion remains applicable to the containment purge valves due to failure in the control circuit associated with each valve. Again, the purge system valve design precludes a single failure from compromising the containment boundary as long as the system is operated in accordance with the subject LCO.

Sealed closed barriers include blind flanges and sealed closed isolation valves including closed manual valves, closed remote-manual valves, and closed automatic valves which remain closed after a loss-of-coolant accident. Sealed closed barriers may be used in place of any automatic isolation valve. The term sealed closed, as applied to containment isolation valves, is not intended to describe leak tightness. Sealed closed isolation valves must be under administrative controls that assure the valve cannot be inadvertently opened. Administrative controls includes mechanical devices to seal or lock the valve closed, or to prevent power from being supplied to the valve operator (Ref. 3).

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36.

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 36 inch purge valves must be maintained sealed closed.

(continued)

BASES

LCO (continued)	The valves covered by this LCO are listed in the FSAR (Ref. 2). The passive isolation devices are shown on drawings in the FSAR. The normally closed isolation valves are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact (Ref. 3). Manually operated containment isolation valves on essential lines that are required to be open, at least for a time, during post accident conditions are OPERABLE if they can be closed in accordance with design assumptions. Essential lines are those lines required to mitigate an accident, or which, if unavailable, could increase the magnitude of the event. Also, those lines which, if available, would be used in the short term (24 to 36 hours) to restore the plant to normal operation following an event which has resulted in containment isolation (Ref. 4). This LCO provides assurance that the containment isolation valves and purge valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.
APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed in LCO 3.9.3, Containment Penetrations.
ACTIONS	The ACTIONS are modified by Note 1 which allows penetration flow paths, except for 36 inch purge valve penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment

(continued)

BASES

ACTIONS (continued)

isolation is indicated. Due to the size of the containment purge line penetration and the fact that those penetrations exhaust from the containment atmosphere to the environment, the penetration flow path containing these valves may not be opened under administrative controls.

The normally stationed control room operator satisfies the requirement for a dedicated operator for any non-automatic, remotely operated CIV that is opened intermittently from the control room (Ref. 6). Additionally, a dedicated operator is not required for manually operated CIVs required to be open both during normal plant operations and during a LOCA. A dedicated operator is not required at the valve when the RHR Suction isolation valve, AC-732, is open to support operation of the RHR system for shutdown cooling (Ref. 6). Normally open, manual CIVs are used for isolation of closed systems within the containment that are missile protected and are seismic Class I at least up to and including the isolation valves.

Note 2 has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable containment isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are further modified by Note 3, which ensures appropriate remedial actions are taken if the affected systems are rendered inoperable by an inoperable containment isolation valve.

In the event containment isolation valve leakage results in exceeding the overall containment leakage rate, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

The ACTIONS are further modified by Note 5 and Note 6, which ensures appropriate remedial actions are taken if required IVSW

(continued)

BASES

ACTIONS (continued)

or WC&PPS supply to a penetration flowpath is inoperable. Note 5 and Note 6 direct entry into the applicable Conditions and Required Actions of LCO 3.6.9 and LCO 3.6.10, as appropriate.

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable, except for containment bypass leakage or hydrostatically tested valve leakage not within limit, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured (Ref. 3). For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. This action involves verification, through a system walkdown, that isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment e.g., one of the three containment

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

pressure relief isolation valves, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two or more containment isolation valves. Although most penetrations have two containment isolation valves, the term “two or more” is used so that Condition A includes penetrations such as the pressure relief line penetration which has three valves in series. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides the appropriate actions.

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these devices once they have been verified to be in the proper position, is small.

B.1

With two or more containment isolation valves in one or more penetration flow paths inoperable, except for containment bypass leakage or hydrostatically tested valve leakage, the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1. In the event the affected penetration is isolated in accordance with

(continued)

BASES

ACTIONS

B.1 (continued)

Required Action B.1, the affected penetration must be verified to be isolated on a periodic basis per Required Action A.2, which remains in effect. This periodic verification is necessary to assure leak tightness of containment and that penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative control and the probability of their misalignment is low.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two or more containment isolation valves. Although most penetrations have two containment isolation valves, the term “two or more” is used so that Condition B includes penetrations such as the pressure relief line penetration which has three valves in series. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path.

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier, other than the closed system, that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange (Ref. 3). A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system. The closed system must meet the requirements of Reference 3.

Required Action C.2 is modified by a Note that applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

D.1

With the containment bypass leakage rate not within limit of TS 5.5.15, the assumptions of the safety analyses are not met. Therefore, the leakage must be restored to within limit within 4 hours. Restoration can be accomplished by isolating the penetration(s) that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed

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BASES

ACTIONS

D.1 (continued)

to be the lesser actual pathway leakage of the two devices. The 4 hour Completion Time is reasonable considering the time required to restore the leakage by isolating the penetration(s) and the relative importance of containment bypass leakage to the overall containment function.

With the hydrostatically tested valve leakage not within limit of SR 3.6.3.9, the potential exists for flooding the Containment Recirculation Pumps during long term post-accident cooling. The 72 hour Completion Time is reasonable because of the low probability of an event occurring during this period.

E.1 and E.2

If the Required Actions and associated Completion Times 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 6 hours and to MODE 5 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 3.6.3.1

Each 36 inch containment purge supply and exhaust isolation valve (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) is required to be verified sealed closed at 31 day intervals. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a containment purge valve. Detailed analysis of the purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to limit offsite doses. Therefore, these valves are required to be in the sealed closed position during MODES 1, 2, 3, and 4. A containment purge valve that is sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or by removing the air supply to the valve operator.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1 (continued)

In this application, the term "sealed" has no connotation of leak tightness. The Frequency is a result of an NRC initiative, Generic Issue B-24 (Ref. 5), related to containment purge valve use during plant operations.

SR 3.6.3.2

This SR ensures that the containment pressure relief line isolation valves (PCV-1190, PCV-1191, and PCV-1192) are closed as required or, if open, open for an allowable reason. If a containment pressure relief line isolation valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is not required to be met when the containment pressure relief line isolation valves are open for the reasons stated. The valves may be opened for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. The containment pressure relief line isolation valves are capable of closing in the environment following a LOCA as long as valve opening angle is limited in accordance with SR 3.6.3.7. Therefore, these valves are allowed to be open for limited periods of time. The 31 day Frequency is consistent with other containment isolation valve requirements discussed in SR 3.6.3.3.

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3 (continued)

containment isolation valves outside containment and capable of being mispositioned are in the correct position. Since verification of valve position for containment isolation valves outside containment is relatively easy, the 31 day Frequency is based on engineering judgment and was chosen to provide added assurance of the correct positions. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed or otherwise secured in the closed position because these valves were verified to be in the correct position when locked, sealed or otherwise secured.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.4

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.4 (continued)

administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed or otherwise secured in the closed position because these valves were verified to be in the correct position when locked sealed or otherwise secured.

This Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4, for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

SR 3.6.3.5

Verifying that the isolation time of each automatic power operated containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses as specified in the FSAR. The isolation time and Frequency of this SR are in accordance with the Inservice Testing Program.

SR 3.6.3.6

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.6 (continued)

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 this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.7

Verifying that each containment pressure relief line isolation valve, PCV-1190, PCV-1191, and PCV-1192, is blocked to restrict valve opening to $\leq$ 60 degrees, is required to ensure that the valves can close under DBA conditions within the times assumed in the analyses of References 1 and 2. If a LOCA occurs, the pressure relief line valves must close to maintain containment leakage within the values assumed in the accident analysis. The 24 month Frequency is appropriate because the blocking devices are typically not removed.

SR 3.6.3.8

This SR ensures that manually operated containment isolation valve on essential lines are capable of being opened or closed as needed to support any accident mitigation function. Essential lines are those lines required to mitigate an accident, or which, if unavailable, could increase the magnitude of the event. Also, those lines which, if available, would be used in the short term (24 to 36 hours) to restore the plant to normal operation following an event which has resulted in containment isolation (Ref. 4). The 24 month Frequency is based on engineering judgement and plant experience with manually operated valves.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.9

The Containment Leakage Rate Testing Program includes verification that inleakage rate from the containment isolation valves sealed with service water is maintained at a level that will prevent flooding the internal recirculation pumps for the full 12-month period of post accident recirculation. This inleakage test has specific acceptance criteria ($\leq$ 0.36 gpm per fan cooler unit when pressurized at $\geq$ 1.1 P_a) specified in the Containment Leakage Rate Testing Program and the results for this inleakage test are not counted against the acceptance criteria for the Type B and C tests that are also performed as part of the SR.

REFERENCES

1. FSAR, Section 14.
2. FSAR, Section 6.
3. Standard Review Plan Section 6.2.4.
4. FSAR, Section 5.2.
5. Generic Issue B-24.
6. Safety Evaluation Report for IP3 Amendment 195.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). The containment can withstand an internal vacuum of 3 psig. The 2.0 psig vacuum specified as an operating limit avoids any difficulties with motor cooling.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer pressure transients. Cycle specific analysis results indicate that the worst case peak containment pressure could result from either a loss of coolant accident or a steam line break inside containment (Ref. 1).

The initial pressure condition used in the containment analysis was +1.5 psig. Sensitivity studies have demonstrated that if RWST temperature is $\leq 95^0$F and containment/accumulator temperatures are $\leq 125^0$F, an initial containment pressure of +2.5 psig would also be acceptable. This analysis concluded that the containment design pressure of 47 psig would not be exceeded for either a major loss-of-coolant accident or for a main steam line break accident. The containment analysis results are presented in Reference 1 and the current value for peak containment pressure is listed in Specification 5.5.15, "Containment Leakage Rate Testing Program."

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment was also designed for an external pressure load equivalent to -3.0 psig (i.e., the containment can withstand an internal vacuum of 3 psig). The -2.0 psig specified as the Limiting Condition for Operation is based on limits associated with motor cooling.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 2).

Containment pressure satisfies Criterion 2 of 10 CFR 50.36.

LCO

Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit ensures that motor heating concerns are addressed.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3 and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.

(continued)

BASES

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If containment pressure cannot be restored to within limits 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 6 hours and to MODE 5 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 3.6.4.1

Verifying that containment pressure is within limits ensures that unit operation remains within the limits assumed in the containment analysis. The 12 hour Frequency of this SR was developed based on operating experience related to trending of containment pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment pressure condition.

REFERENCES

1. FSAR, Section 14.3

2. 10 CFR 50, Appendix K.

3. FSAR Section 3.1.8, Appendix 5A.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND

The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment average air temperature is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB).

The containment average air temperature limit is derived from the input conditions used in the containment functional analyses and the containment structure external pressure analyses. This LCO ensures that initial conditions assumed in the analysis of containment response to a DBA are not violated during unit operations. The total amount of energy to be removed from containment by the Containment Spray and Cooling systems during post accident conditions is dependent upon the energy released to the containment due to the event, as well as the initial containment temperature and pressure. The higher the initial temperature, the more energy that must be removed, resulting in higher peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis. Operation with containment temperature in excess of the LCO limits violates an initial condition assumed in the accident analysis.

APPLICABLE SAFETY ANALYSES

Containment average air temperature is an initial condition used in the DBA analyses that establishes the containment environmental qualification operating envelope for both pressure and temperature. The upper limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The lower limit is to assure that the minimum service metal temperature of the containment liner is well above the NDT + 30^{0}F criterion for the liner material (Ref. 3).

The limiting DBAs considered relative to containment OPERABILITY are the LOCA and SLB. The DBA LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train each of the Containment Spray System, Residual Heat Removal System, and Containment Cooling System being rendered inoperable.

The limiting DBA for the maximum peak containment air temperature may be either a LOCA or a SLB. The initial containment average air temperature is assumed in the design basis analyses. The maximum containment air temperature and the design temperature are specified in (Ref. 1). The temperature limit is also used to establish the environmental qualification operating envelope for containment. In accordance with NRC Division of Operating Reactors (DOR) Guidelines and the Environmental Qualification Program (Ref. 6), the regulatory basis for environmental qualification inside containment is established by a LOCA, which is considered bounding DBA.

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure may be either a

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

LOCA or a SLB. The upper temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

The initial containment temperature is also an input to the analysis for determining the peak clad temperature (PCT). The PCT analysis is for a LOCA at rated power (Mode 1) and assumes an initial temperature of 90°F. A LOCA in Modes 2, 3 and 4 at a lower containment temperature (> 50°F) will be bounded by the LOCA at rated power (Ref. 4). A lower initial containment temperature of 80°F at rated power is desirable, and an evaluation (Ref. 5) determined that a 10°F reduction in initial containment temperature would result in a slight increase in PCT.

Procedural controls ensure that containment air temperature is above 80°F during operation at power.

Containment average air temperature satisfies Criterion 2 of 10 CFR 50.36.

LCO

During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature upper limit, the resultant peak accident temperature is maintained below the containment design temperature. As a result, the ability of containment to perform its design function is ensured.

The lower limit for containment average air temperature assures that the containment liner temperature is maintained well above the NDT temperature.

The LCO limits for containment temperature are analytical limits. Therefore, an appropriate allowance for instrument uncertainty must be applied when ensuring these limits are met.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limits is not required in MODE 5 or 6.

(continued)

ACTIONS

A.1

When containment average air temperature is $\leq 50^{0}F$, it must be restored within limits immediately. This required action is necessary to ensure that a sufficient margin of safety is maintained so the NDT limit is not compromised. The completion time of immediately ensures that containment temperature is restored to within limits without delay.

B.1

When containment average air temperature is greater than $130^{0}F$, it must be restored to within limits within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems.

C.1 and C.2

If the containment average air temperature cannot be restored to within its limits 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 6 hours and to MODE 5 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 3.6.5.1

Verifying that containment average air temperature is within the LCO limits ensures that containment operation remains within the limits assumed for the containment analyses. In order to determine the containment average air temperature, an arithmetic average is calculated using measurements taken at locations within the containment selected to provide a representative sample of the overall containment atmosphere.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1 (continued)

A representative measurement of containment air temperature requires an arithmetic average of temperatures measured at no fewer than 4 locations. Environmentally and seismically qualified RTDs mounted on the crane wall above the containment fan cooler units inlet are normally used for measuring containment ambient temperature. Experience dictates that at least 4 fan cooler units should be operating to achieve adequate mixing of air to assure a representative measurement of containment air temperature. Portable temperature sensing equipment may also be used.

The 24 hour Frequency of this SR is considered acceptable based on observed slow rates of temperature increase within containment as a result of environmental heat sources (due to the large volume of containment). 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 containment temperature condition.

REFERENCES

1. FSAR, Section 14.3.
2. 10 CFR 50.49.
3. FSAR, Section 5.1.
4. IPP-09-14/INT-09-028, Operability Assessment for Indian Point Units 2 and 3 at a Containment Temperature of 50°F in Modes 2, 3 and 4, June 16, 2009.
5. INT-08-14, Evaluation of Containment Sump Strainer Modifications, Reduced Containment Initial Temperature and Accumulator Water Temperature on Indian Point Unit 3 (INT) Best Estimate Large Break LOCA Analysis, August 13, 2008.
6. IP3 Environmental Qualification Program (EQPM), 8/7/2001.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray System and Containment Fan Cooler System

BASES

BACKGROUND

The Containment Spray System and Containment Fan Cooler System provide containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine removal capability reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA), to within limits. The Containment Spray and Containment Fan Cooler systems are designed to meet the requirements of 10 CFR 50, Appendix A, GDC 38, "Containment Heat Removal," GDC 39, "Inspection of Containment Heat Removal Systems," GDC 40, "Testing of Containment Heat Removal Systems," GDC 41, "Containment Atmosphere Cleanup," GDC 42, "Inspection of Containment Atmosphere Cleanup Systems," and GDC 43, "Testing of Containment Atmosphere Cleanup Systems" (Ref. 1).

The Containment Spray System and Containment Fan Cooler System are Engineered Safety Feature (ESF) systems. They are designed to ensure that the heat removal capability required during the post accident period can be attained. The Containment Spray System and the Containment Fan Cooler System provide redundant methods to limit and maintain post accident conditions to less than the containment design values.

Containment Spray System

The Containment Spray System consists of two separate trains. Each train includes a containment spray pump, piping and valves and is independently capable of delivering one-half of the design flow needed to maintain the post-accident containment pressure below 47 psig. The spray water is injected into the containment through spray nozzles connected to four 360 degree ring headers located in the containment dome area. Each train supplies two of the four ring headers. Each train is powered from a separate safeguards power train. The refueling water storage tank (RWST) supplies borated water to the Containment Spray System during the injection phase of operation.

(continued)

BASES

BACKGROUND (continued)

After the Refueling Water Storage Tank has been exhausted, the containment recirculation pumps or the Residual Heat Removal (RHR) pumps are used to supply the Containment Spray ring headers for the long-term containment cooling and iodine removal during the containment recirculation phase. In this configuration, the RHR heat exchangers provide the necessary cooling of the recirculated containment spray.

The Containment Spray System provides a spray of cold borated water into the upper regions of containment to reduce the containment pressure and temperature. Additionally, these systems reduce fission products from the containment atmosphere during a DBA. The RWST solution temperature is an important factor in determining the heat removal capability of the Containment Spray System during the injection phase. In the recirculation mode of operation, heat is removed from the containment sump or recirculation sump water by the residual heat removal heat exchangers. Both trains of the Containment Spray System are needed to provide adequate spray coverage to meet the system design requirements for containment heat removal assuming the Fan Cooler System is not available.

The Recirculation pH Control System functions by dissolving STB into the Containment Spray water. The resulting alkaline pH of the spray enhances the ability of the spray to scavenge fission products from the containment atmosphere. The STB dissolved in the spray water ensures an alkaline pH for the solution recirculated in the containment sump. The alkaline pH of the containment sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The Containment Spray System is actuated either automatically by a containment High-High pressure signal or manually. An automatic actuation starts the two containment spray pumps, opens the containment spray pump discharge valves, and begins the injection phase. A manual actuation of the Containment Spray System requires the operator to actuate two separate push buttons on the main control board to begin the same sequence. The injection phase continues until the RWST water supply is exhausted. After the Refueling Water Storage Tank has been exhausted, the containment recirculation pumps or the

(continued)

BASES

BACKGROUND (continued)

residual heat removal (RHR) pumps may be used to supply the Containment Spray ring headers for the long-term containment cooling and iodine removal during the containment recirculation phase. In this configuration, the RHR heat exchangers provide the necessary cooling of the recirculated containment spray. The Containment Spray function in the recirculation mode may be used to maintain an equilibrium temperature between the containment atmosphere and the recirculated sump water. The Containment Spray function in the recirculation mode is controlled by the operator in accordance with the emergency operating procedures.

Containment Fan Cooler System

The Containment Fan Cooler System consists of five 20% capacity Fan Cooler Units (FCUs) located inside containment. These FCUs are used for both normal and post accident cooling of the containment atmosphere. Each FCU consists of a motor, fan, cooling coils, moisture separators, HEPA filters, carbon filters, dampers, duct distribution system, instrumentation and controls. Service water is supplied to the cooling coils to perform the heat removal function.

During normal plant operation, the moisture separators, HEPA filters and activated carbon filter assembly are isolated from the main air recirculation stream. In this configuration, service water is supplied to all five FCUs and two or more FCUs fans are typically operated to limit the ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

In post accident operation following an actuation signal, the Containment Cooling System fans are designed to start automatically. Additionally, the actuation signal causes the air flow (air-steam mixture) in each FCU to be split into two parts by a bypass flow control damper that fails to a pre-set position for accident operation. A minimum of 8000 cfm is directed through the FCU filtration section (moisture separators, HEPA filters, and carbon filter assembly) with the remainder of the air flow bypassing the

(continued)

BACKGROUND (continued)

filtration section. Both the filtered and unfiltered FCU flow passes through the cooling coils. The temperature of the service water is an important factor in the heat removal capability of the fan units. The accident analysis assumes 1400 gpm of service (cooling) water with a maximum river water inlet temperature of 95°F is supplied to each FCU.

Containment Cooling and Iodine Removal Function

The containment cooling and iodine removal functions are provided by a combination of the containment spray and the containment fan cooler systems.

Requirements for Containment Spray Trains may be designated by the number of the containment spray pump or the associated safeguards power train. Containment Spray Train 31 is associated with Safeguards Power Train 5A which is supported by DG 33. Containment Spray Train 32 is associated with Safeguards Power Train 6A which is supported by DG 32.

Requirements for the five fan cooler units are designated by grouping the 5 fan cooler units into three trains based on the safeguards power train needed to support Operability. This results in the following designations:

Fan Cooler Train 5A consists of FCU 31 and FCU 33;

Fan Cooler Train 2A/3A consists of FCU 32 and FCU 34; and

Fan Cooler Train 6A consists of FCU 35.

The configuration with one containment spray train and two fan cooler trains is the configuration available following the loss of any safeguards power train (e.g., diesel failure).

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BASES

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Fan Cooler System limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the loss of one safeguards power train, which is the worst case single active failure and results in one train of Containment Spray and one train of Fan Coolers being rendered inoperable.

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure and temperature may result from either a LOCA or SLB, depending on the cycle specific analysis (Refs. 4 and 6). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.) The analyses and evaluations assume a unit specific power level of 102% and initial (pre-accident) containment conditions of 130^0F and 2.5 psig and a service water inlet temperature of 95^0F. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative.

In particular, the effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures in accordance with 10 CFR 50, Appendix K (Ref. 2).

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The effect of an inadvertent containment spray activation has been analyzed. An inadvertent spray activation results in a rapid reduction of containment pressure and is associated with the sudden cooling effect in the interior of a leak tight containment. Additional documentation is provided in the Bases for LCO 3.6.4.

The modeled Containment Spray System actuation from the containment analysis is based on a response time associated with exceeding the containment High-High pressure setpoint to achieving full flow through the containment spray nozzles. The Containment Spray System total response time includes diesel generator (DG) startup (for loss of offsite power), loading of equipment, containment spray pump startup, and spray line filling.

Containment cooling train performance for post accident conditions is given in References 3, 4 and 6. The result of the analysis is that accident analysis assumptions regarding containment air cooling and iodine removal are met by one containment spray train and any two fan cooler trains (i.e., at least three fan cooler units).

This configuration is the configuration available following the loss of any safeguards power train (e.g., diesel failure).

The modeled Containment Cooling System actuation from the containment analysis is based upon a response time associated with exceeding the containment High-High pressure setpoint to achieving full Containment Fan Cooler System air and safety grade cooling water flow.

The Containment Cooling System total response time includes signal delay, DG startup (for loss of offsite power), and service water pump startup times (Ref.4).

The Containment Spray System and Containment Fan Cooler System satisfy Criterion 3 of 10 CFR 50.36.

(continued)

BASES

LCO

Accident analysis assumptions regarding containment air cooling and iodine removal are met by one containment spray train and any two fan cooler trains (i.e., at least three fan cooler units).

This configuration is the configuration available following the loss of any safeguards power train (e.g., diesel failure).

Each Containment Spray System includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal.

Each FCU consists of a motor, fan, cooling coils, moisture separators, HEPA filters, carbon filters, dampers, duct distribution system, instrumentation and controls necessary to maintain an OPERABLE flow path for the containment atmosphere through both the filtration unit and cooling coils and an OPERABLE flow path for service water through the cooling coils.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature requiring the operation of the containment spray trains and containment cooling trains.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the Containment Spray System and Containment Fan Cooler System are not required to be OPERABLE in MODES 5 and 6.

(continued)

BASES

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE spray and fan cooler trains are adequate to perform the iodine removal and containment cooling functions. The 72 hour Completion Time takes into account the redundant heat removal capability afforded by the Containment Spray System, reasonable time for repairs, and low probability of a DBA occurring during this period.

The 10 day portion of the Completion Time for Required Action A.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident occurring during this time. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

B.1 and B.2

If the inoperable containment spray train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 54 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 7). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 7, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

The extended interval to reach MODE 4 allows 48 hours to restore the containment spray train to OPERABLE status in MODE 3, and is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

C.1

With one of the required containment fan cooler trains inoperable, the inoperable required containment fan cooler train must be restored to OPERABLE status within 7 days. The components in this degraded condition provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs. The 7 day Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray System and Containment Fan Cooler System and the low probability of DBA occurring during this period.

The 10 day portion of the Completion Time for Required Action C.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident occurring during this time. Refer to Section 1.3 for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

(continued)

ACTIONS (continued)

D.1

With two required containment fan cooler trains inoperable, one of the required containment cooling trains must be restored to OPERABLE status within 72 hours. This allowable out of service time is acceptable because the minimum required containment cooling and iodine removal function is maintained even though this configuration is a substantial degradation from the design capability, and may be a loss of redundancy for this function.

E.1 and E.2

If the Required Action and associated Completion Time of Condition C or D of this LCO are not met, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 7). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 7, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action E.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

(continued)

BASES

ACTIONS (continued)

F.1

With two containment spray trains or any combination of three or more containment spray and fan cooler trains inoperable, the unit could be in a condition outside the accident analysis. Entering this Condition represents a substantial degradation of the containment heat removal and iodine removal function. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves in the containment spray flow path provides assurance that the proper flow paths will exist for Containment Spray 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, through a system walkdown, that those valves outside containment (check valves are inside containment) and capable of potentially being mispositioned are in the correct position. Valves in containment with remote position indication may be checked using remote position indication.

SR 3.6.6.2

Operating each containment fan cooler unit for ≥ 15 minutes ensures that all fan cooler units 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. The 92 day Frequency was developed considering fan coolers are operated during normal plant operation, the known reliability of the fan units and controls, the two train redundancy available, and the low probability of significant degradation of the containment fan cooler units occurring between surveillances. It has also been shown to be acceptable through operating experience.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.3

Verifying that the service water flow rate to each fan cooler unit is ≥ 1400 gpm provides assurance that the design flow rate assumed in the safety analyses will be achieved (Ref. 3). The 92 day Frequency was developed considering the known reliability of the Cooling Water System, the redundancy available, and the low probability of a significant degradation of flow occurring between surveillances.

SR 3.6.6.4

Verifying each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by the ASME Code (Ref. 5). Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by abnormal performance. The Frequency of the SR is in accordance with the Inservice Testing Program.

SR 3.6.6.5 and SR 3.6.6.6

These SRs require verification that each automatic containment spray valve actuates to its correct position and that each containment spray pump starts upon receipt of an actual or simulated actuation of a containment High-High pressure signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The tests are performed with the isolation valves in the spray supply lines at the containment and the spray additive tank isolation valves blocked closed.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.7

This SR requires verification that each containment fan cooler unit starts and damper re-positions to the emergency mode upon receipt of an actual or simulated safety injection signal. The 24 month Frequency is based on engineering judgment and has been shown to be acceptable through operating experience. See SR 3.6.6.5 and SR 3.6.6.6, above, for further discussion of the basis for the 24 month Frequency.

SR 3.6.6.8

This SR verifies that the required Fan Cooler Unit testing is performed in accordance with Specification 5.5.10, Ventilation Filter Testing Program (VFTP). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.6.9

With the containment spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections. This SR ensures that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. Due to the passive design of the nozzle, a test at 10 year intervals is considered adequate to detect obstruction of the nozzles.

(continued)

BASES

REFERENCES

1. 10 CFR 50, Appendix A.
2. 10 CFR 50, Appendix K.
3. FSAR, Sections 6.3 and 6.4.
4. FSAR, Section 14.3 Table 14.3-56.
5. ASME code for Operation and Maintenance of Nuclear Power Plants.
6. WCAP – 16212P, Indian Point Nuclear Power Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report, June 2004.
7. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Recirculation pH Control System

BASES

BACKGROUND

The Recirculation pH Control System is a passive safeguard with baskets of sodium tetraborate decahydrate (STB), or equivalent, that assists in reducing the iodine fission product inventory in the containment atmosphere resulting from a Design Basis Accident (DBA).

Radioiodine in its various forms is the fission product of primary concern in the evaluation of a DBA. It is absorbed by the spray from the containment atmosphere. To enhance the iodine retention capacity of the spray during recirculation from the sump, the spray solution is adjusted to an alkaline pH that promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. The sodium tetraborate decahydrate (STB) is stored in baskets in the containment building. The initial spray, a boric acid solution from the refueling water storage tank has a pH of about 4.5. As the initial spray solution and, subsequently the recirculation solution comes in contact with the STB, the STB dissolves raising the pH of the sump solution. Reference 2 indicates that the pH should be between 7.0 and 9.5 and that the potential for increased hydrogen generation from aluminum should be addressed at pH greater than 7.5. An alkaline pH minimizes the evolution of iodine as well as the occurrence of chloride and caustic stress corrosion on mechanical systems and components.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

Following the assumed release of radioactive materials into containment, the containment is assumed to leak at its design value volume following the accident. The analysis assumes that 80% of containment is covered by the spray (Ref. 1). The pH of the initial spray from the RWST is about 4.5.

The Recirculation pH Control System is a passive safeguard with the baskets of STB located in the containment. The initial spray solution and subsequently the recirculation solution come in contact with the STB in the baskets and dissolves to raise the pH. The Recirculation pH System is OPERABLE when there is sufficient STB available to guarantee a sump pH of ≥7.0 during the recirculation phase of a postulated LOCA. Calculation of pH was performed for STB. The mass of STB required to provide an equilibrium sump pH solution of about 7.1 is 8,096 pounds. A 10,000 mass of STB provides a sump pH of about 7.2.

The Recirculation pH Control System satisfies Criterion 3 of 10 CFR 50.36.

LCO

The Recirculation pH Control System reduces the release of radioactive material to the environment in the event of a DBA. To be considered OPERABLE, the STB baskets must be in place and intact and collectively contain ≥8,096 pounds (160 cubic feet) of STB or equivalent.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the Recirculation pH Control System. The Recirculation pH Control System assists in reducing the iodine fission product inventory prior to release to the environment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the Recirculation pH Control System is not required to be OPERABLE in MODE 5 or 6.

(continued)

BASES

ACTIONS

A.1

If the Recirculation pH Control System is inoperable, it must be restored to OPERABLE within 72 hours. The pH adjustment for corrosion protection and iodine removal enhancement is reduced in this condition. The Containment Spray System and Containment Fan Cooler System are available and would remove iodine from the containment atmosphere in the event of a DBA. The 72 hour Completion Time takes into account the redundant flow path capabilities and the low probability of the worst case DBA occurring during this period.

B.1 and B.2

If the Recirculation pH Control System cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 54 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 3). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 3, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

(continued)

BASES

ACTIONS (continued)

The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 4 allows 48 hours for restoration of the Recirculation pH Control System in MODE 3. This is reasonable when considering the reduced pressure and temperature conditions in MODE 3 for the release of radioactive material from the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

This SR provides visual verification that each of the eight storage sodium tetraborate baskets is in place and intact and collectively contain ≥ 8,096 pounds (160 cubic feet) of sodium tetraborate decahydrate, or equivalent. This amount of STB is sufficient to ensure that the recirculation solution following a LOCA is at the correct pH level. The 24 month frequency is sufficient to ensure that the stainless steel baskets are intact and contain the appropriate amount of STB.

REFERENCES

1. FSAR, Chapters 6 and 14.

2. NUREG-0800, "Standard Review Plan," Section 6.5.2, "Containment Spray as a Fission Product Cleanup System," Revision 4 dated March 2007 containing Branch Technical Position 6-1 “pH For Emergency Coolant Water for Pressurized Water Reactors” Revision 0 dated March 2007.

3. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Not Used

B 3.6 CONTAINMENT SYSTEMS

B 3.6.9 Isolation Valve Seal Water (IVSW) System

BASES

BACKGROUND

The Isolation Valve Seal Water (IVSW) System improves the effectiveness of certain containment isolation valves (CIVs) by providing a water seal to valve leakage paths. This is accomplished by injecting water between the seats and stem packing of globe and double-disk type isolation valves and into the piping between other closed containment isolation valves. IVSW sealing water is maintained in a seal water supply tank filled with water and pressurized with nitrogen. The IVSW System is actuated in conjunction with automatic initiation of containment isolation and is applied to CIVs in lines connected to the Reactor Coolant System or exposed to the containment atmosphere during an accident. The seal water is injected at a pressure of at least 47 psig which is >1.1 times the calculated peak containment pressure (P_a). For those valves sealed by IVSW, the possibility of leakage from the Containment or Reactor Coolant System to the atmosphere outside containment is eliminated because leakage will be from the IVSW system into the Containment.

The containment is designed with an allowable leakage rate not to exceed 0.1% of the containment air weight per day. The maximum allowable leakage rate is used to evaluate offsite doses resulting from a DBA. Confirmation that the leakage rate is within limit is demonstrated by the performance of a Type A leakage rate test in accordance with the Containment Leakage Rate Testing Program as required by LCO 3.6.1, "Containment." During the performance of the Type A test, no credit is taken for the IVSW System in meeting the containment leakage rate criteria. As such, in the event of a DBA without an OPERABLE IVSW System, both the whole body and thyroid offsite doses would be within the guidelines specified in 10 CFR Part 50.67.

Although IVSW is not needed to maintain plant releases such that the whole body and thyroid offsite doses would be within the guidelines specified in 10 CFR Part 100 based on Type A leakage testing, Indian

(continued)

BASES

BACKGROUND (continued)

Point 3 elected to consider IVSW as a seal system as described in Reference 3. This election allows leakage through CIVs sealed by IVSW to be excluded when calculating Type B and C testing results. Therefore, operation of IVSW is an implicit assumption in the calculation of post accident offsite radiation doses.

To satisfy the requirements of Reference 3, for excluding leakage from CIVs sealed by IVSW from Type B and C limits, Technical Specifications must ensure the IVSW sealing function (i.e., both sealing water supply and nitrogen gas supply) is maintained at a pressure of 1.10 P_a for at least 30 days.

Sealing water design capacity is sufficient to maintain a source of seal water at the required pressure for a minimum of 24 hours without operator intervention assuming worst case leakage and the single failure of a CIV sealed by IVSW. The requirements for a 24 hour supply of seal water under worst case conditions is satisfied by maintaining a minimum of 144 gallons in the 176 gallon capacity seal water tank.

Nitrogen gas for IVSW seal water pressurization is satisfied by having three compressed nitrogen bottles in the IVSW supply bank aligned to the IVSW supply tank.

To satisfy the requirement of Reference 3 for maintaining the IVSW sealing function for at least 30 days, manual operator action may be required to replenish the IVSW seal water supply and/or compressed gas supply. Two sources of makeup water and two alternate sources of compressed gas with sufficient capacity to maintain the IVSW sealing function for 30 days are available. The two sources of makeup water are the primary water storage tank and the city water system. The two alternate sources of compressed gas are the normally isolated nitrogen gas bottles in the nitrogen supply bank and the ability to refill or replace the IVSW nitrogen supply bottles from the plant Nitrogen System. Manual operations required to supply makeup water and gas to the IVSW system are performed in an area that is accessible during

(continued)

BASES

BACKGROUND (continued)

an accident. The IVSW tank is instrumented to provide local indication of pressure and water level. Low water level, low pressure and high pressure in the IVSW supply tank are alarmed.

The IVSW System distribution piping consists of five headers. Three of the five IVSW headers are pressurized by opening either of a pair of normally closed air operated header injection valves. These valves open automatically on a containment Phase "A" isolation signal to admit seal water to the associated CIVs. One of the five IVSW headers is pressurized by opening either of a pair of normally closed, air-motor operated, header injection valves. These valves open automatically on a containment Phase "A" isolation signal to admit seal water to the associated CIVs. One IVSW header is used to supply seal water to CIVs on process lines that are not automatically closed on a containment Phase "A" isolation signal. This header is normally pressurized by the IVSW System with a normally closed manual or air-motor operated isolation valve for each pair of CIVs served by this IVSW header.

Redundant automatic header injection valves in parallel ensures the IVSW header is pressurized if there is a failure of one injection valve. Each of the two automatic header injection valves in each pair are actuated from separate and independent signals.

A related system, the Isolation Valve Seal Gas System, is not credited as a seal system as described in Reference 3, and is not addressed by this Technical Specification. This system uses the nitrogen bank used to supply the IVSW System to supply high pressure nitrogen that may be used to seal lines subjected to pressure in excess of the 150 psig IVSW design pressure due to operation of the recirculation pumps. This system is manually initiated during the post accident recovery phase and is not part of the IVSW System.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The IVSW System LCO was derived from the requirement related to the control of leakage from the containment during major accidents. This LCO is intended to ensure the actual containment leakage rate is maintained within the maximum value assumed in the safety analyses. As part of the containment boundary, containment isolation valves function to support the leak tightness of the containment. The IVSW System assures the effectiveness of certain containment isolation valves by providing a water seal pressurized to $\geq$ 1.1 times the maximum peak containment accident pressure at the valves and thereby reducing containment leakage. As such, the IVSW System is considered a seal system as described in Reference 3. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

The DBA that results in a release of radioactive material within containment is a loss of coolant accident (LOCA)(Ref. 2). The DBAs assume that, within 60 seconds after the accident, isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a. The containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power) and containment isolation valve stroke time. The IVSW System actuates on a containment isolation signal and functions within 60 seconds to help reduce containment leakage within the allowable design leakage rate value, L_a.

The Isolation Valve Seal Water System satisfies Criterion 3 of 10 CFR 50.36.

LCO

OPERABILITY of the IVSW System is based on the system's capability to supply seal water to selective containment isolation valves within the time assumed in the applicable safety analyses and to ensure pressure is maintained for at least 30 days. This requires the IVSW tank be maintained with an adequate volume of water, an air or nitrogen overpressure sufficient to provide the motive force to move the water to the applicable penetration, piping to provide an OPERABLE flow

(continued)

BASES

LCO (continued)

path and two air operated header injection valves on each automatically actuated branch header.

APPLICABILITY

The IVSW System is required to be OPERABLE in MODES 1, 2, 3, and 4 because a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the IVSW System is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

A.1

With one IVSW System header inoperable, a portion of the CIVs serviced by IVSW may not receive seal water at the required pressure and volume for effective sealing. However, the CIVs are OPERABLE and will still close, the affected CIVs provide adequate isolation to meet containment isolation requirements without IVSW during the most recent Type A test, and the number of CIVs affected by the failure of one IVSW header is small compared to the total number of CIVs. Therefore, the 7 days is allowed to restore the IVSW System header to OPERABLE status.

With one IVSW automatic actuation valve inoperable, the IVSW function is still available because the redundant automatic actuation valve is OPERABLE. Therefore, the 7 days is allowed to restore the IVSW automatic actuation valve to OPERABLE status.

B.1

With the IVSW system inoperable for reasons other than Condition A, the effectiveness of CIVs sealed by IVSW may be compromised. This Condition may result from failure to meet any of the surveillance requirements needed to verify Operability of IVSW or the inoperability of multiple IVSW headers or automatic actuation devices. However, the CIVs are OPERABLE and will still close and the affected CIVs provide adequate isolation to meet containment isolation requirements without

(continued)

BASES

ACTIONS

B.1 (continued)

IVSW during the most recent Type A test. Additionally, except in the unusual case where inoperability is the result of failure to meet SR 3.6.9.5, the affected CIVs have demonstrated the ability to satisfy IVSW leakage requirements using IVSW seal water in lieu of meeting Type C testing requirements. Therefore, the 24 hours is allowed to restore the IVSW System to OPERABLE status.

C.1 and C.2

If the Required Actions and associated Completion Times 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 6 hours and to MODE 5 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 3.6.9.1

This SR verifies the IVSW tank has the necessary pressure to provide motive force to the seal water. A 47 psig pressure is sufficient to ensure the containment penetration flowpaths that are sealed by the IVSW System are maintained at a pressure equal to or greater than 1.1 times the calculated peak containment internal pressure (P_a) related to the design bases accident. Verification of the IVSW tank pressure on a Frequency of once per 24 hours is acceptable because operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.9.2

This SR ensures the capability of the IVSW nitrogen source to pressurize the IVSW system as needed to support IVSW operation for a minimum of 30 days. Verification of the IVSW tank pressure on a Frequency of once per 24 hours is acceptable because operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

SR 3.6.9.3

This SR verifies the IVSW tank has an initial volume of water necessary to provide seal water to the containment isolation valves served by the IVSW System for a period of at least 24 hours assuming the failure of one CIV and the maximum allowed leakage past other CIVs served by IVSW. Verification of IVSW tank level on a Frequency of once per 24 hours is acceptable since tank level is monitored by installed instrumentation and will alarm in the Primary Auxiliary Building prior to level decreasing to 20 gallons which provides sufficient time to re-fill the tank before it is depleted.

SR 3.6.9.4

This SR verifies the stroke time of each automatic IVSW header injection solenoid valve is within limits. The frequency is 24 months. Previous operating experience has shown that these valves usually pass the required test when performed.

SR 3.6.9.5

This SR ensures that automatic header injection valves actuate to the correct position on a simulated or actual signal. 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.9.5 (continued)

reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.6.9.6

Integrity of the IVSW seal boundary is important in providing assurance that the design leakage value required for the system to perform its sealing function is not exceeded. This testing is performed in accordance with the requirements, Frequency and acceptance criteria established in Specification 5.5.15, Containment Leakage Rate Testing Program. This program was established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by IP3 specific approved exemptions. This program conforms to guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program, dated September 1995."

REFERENCES

1. FSAR, Section 6.
2. FSAR, Chapter 14.
3. 10 CFR 50, Appendix J, Option A, Section III. B

B 3.6 CONTAINMENT SYSTEMS

B.3.6.10 Weld Channel and Penetration Pressurization System

BASES

BACKGROUND

The Weld Channel and Penetration Pressurization System (WC&PPS) is designed to continuously pressurize the double penetration barriers used at locations where plant systems penetrate the containment boundary, the space between selected isolation valves, and most of the weld seam channels installed on the inside of the liner of the Containment. Continuous pressurization by the WC&PPS provides a continuous, sensitive, and accurate means of monitoring their status with respect to leakage. Additionally, the WC&PPS is maintained at a pressure above the containment peak accident pressure so that any postulated leakage past the monitored barriers will be into the containment rather than out of the containment. The design basis leakage rate from the WC&PPS is 0.2% of containment free volume per day which assumes leakage of 0.1% of containment free volume per day into the containment and an identical amount leaking to the environment. Following a design basis accident, the system will maintain pressure greater than the post accident containment pressure for 24 hours (Ref. 1).

The WC&PPS is divided into four independent zones to simplify the process of locating leaks during operation. If one zone has a leak during operation, the specific penetration, weld channel, or containment isolation valve (CIV) containing the leak can be identified by isolating the individual air supply line to each component in the zone. Additionally, a capped tube connection installed in each line allows injecting leak test gas (Ref. 1).

The instrument air system provides a regulated supply of clean and dry compressed air for the WC&PPS. Two instrument air compressors are used, although only one is required to maintain pressurization at the maximum allowable leakage rate of the WC&PPS. A backup source of air

(continued)

BACKGROUND (continued)

for the WC&PPS is the station air system which includes at least one station air compressor. Each WC&PPS zone is served by its own air receiver which will continue to supply air to the zone if the instrument air system and station air system are lost. Each of the air receivers is sized to supply air to its zone for a period of at least one hour based on a total leakage rate of 0.2% of the containment free volume per day. If the receivers are exhausted before normal and backup air supplies are restored, additional backup is provided by a bank of nitrogen cylinders. The nitrogen backup system will automatically deliver nitrogen at a pressure slightly lower than the normal regulated air supply. Thus, in the event of failure of the normal and backup air supply systems during periods when the system is in operation, WC&PPS pressure requirements will be automatically maintained by the nitrogen supply. This assures reliable pressurization under both normal and accident conditions. The combination of the air receivers and nitrogen supply is sufficient to ensure WC&PPS pressure is above the peak containment pressure at the start of a LOCA and to maintain WC&PPS above the post-LOCA containment pressure profile for the 24 hour period following a LOCA at the design leakage rate of 0.2% of the containment free volume per day.

Pressure control valves, isolation valves and check valves are generally located outside of the containment for ease of inspection and maintenance. The line to each of the four pressurized zones is equipped with a critical pressure drop orifice to assure that air consumption will be within the capacity of the system and that high air consumption in one zone does not affect the operation of the other zones. Additionally, restricting orifices are installed on pressurization lines, where required, to assure that air consumption, even on failure of an individual line, will not result in loss of pressure to the other components connected to the same pressurization header.

All pressurized components have provisions for either local pressure indication, mounted outside the Containment, or remote low pressure alarms in the Control Room. The actuating pressure for each pressure alarm is set above incident pressure and below the nitrogen supply regulator setting.

(continued)

BASES

BACKGROUND (continued)

WC&PPS air consumption is continuously monitored by a flow sensing device located in each of the headers supplying makeup air to the four WC&PPS zones. Output from these sensors is applied to a summing amplifier which drives a total flow recorder. The flow measurement range is 0-15 scfm with an accuracy of ± 1% of full scale. High flow alarms in the Control Room are derived from the recording channel. With the WC&PPS at 43 psig and the containment at approximately atmospheric pressure, an indicated WC&PPS flow rate of 14.2 scfm is equivalent to the WC&PPS design leakage limit. A WC&PPS flow rate of 14.2 scfm, if sustained for 24 hours, is equivalent to 0.2% of the containment free volume at a pressure of 43 psig.

APPLICABLE SAFETY ANALYSES

For Indian Point 3, offsite dose calculations demonstrate compliance with 10 CFR 50.67 guidelines and the results are well within those guidelines. In these calculations, it is assumed that the Containment leaks at a rate of 0.1% per day of Containment free volume for the first 24 hours and 0.05% per day of Containment free volume thereafter. No credit is taken for the WC&PPS when determining the amount of radioactivity released for offsite dose evaluations because the integrated leakage rate tests required by Specification 5.15, Containment Leakage Rate Testing Program, are performed with the double penetration and weld channel zones open to the containment atmosphere. However, WC&PPS does provide an additional means for ensuring that containment leakage is minimized (Ref. 3).

A design function of WC&PPS is to provide a continuous, sensitive, and accurate means of monitoring leakage of selected containment isolation valves (CIVs), the air lock door seals, and containment welds that are pressurized by this system. WC&PPS leakage, even if below the WC&PPS design leakage rate, may indicate that one of these supported components is exceeding its leakage rate acceptance criteria. In this situation, the supported component may be inoperable and the APPLICABLE SAFETY ANALYSES for the supported component is applicable.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Specification 5.15, Containment Leakage Rate Testing Program, allows an exemption to Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program, and ANS 56.8-1994, Section 3.3.1, in that WC&PPS supply isolation valves are not required to be Type C tested. Note that the WC&PPS supply isolation valves are normally open valves. As specified in Reference 2, operating with these valves normally open and the exemption from type C testing is acceptable because: (1) the WC&PPS is monitored for changes to the system leakage rate; (2) the WC&PPS leakage rate is quantified every 36 months; and, (3) WC&PPS pressure is maintained higher than the containment peak accident pressure (Ref. 2). Therefore, if the required pressure is not maintained or excessive WC&PPS leakage is identified, then compensatory actions are required to ensure the containment boundary is maintained.

<u>For containment isolation valves (CIVs) supported by WC&PPS</u>, WC&PPS pressurization is applied to the space between those CIVs that are normally closed. CIVs supported by WC&PPS are Type C tested in accordance with Specification 5.5.15 because WC&PPS is not credited as a seal system. <u>For loss of WC&PPS pressurization</u>, isolation of the WC&PPS supply to the affected CIVs provides appropriate compensatory action because the supported CIVs are a tested boundary and isolating the depressurized WC&PPS supply eliminates WC&PPS as a potential leakage path. <u>For high WC&PPS air consumption</u>, a consideration is that the leakage may indicate that a supported CIV is exceeding its leakage rate acceptance criteria. If the leakage path is isolated from the supported CIVs when the WC&PPS supply to the CIV is isolated, isolation of the WC&PPS supply to the CIV restores the required safety function. If the leakage path is not isolated from the supported CIV when the WC&PPS supply to the CIV is isolated (i.e., the CIV is depressurized), the supported CIV may be inoperable and the requirements of LCO 3.6.3, "Containment Isolation Valves," are applicable.

<u>For the containment air lock door seals supported by WC&PPS</u>, WC&PPS pressurization is normally applied to the space between the double gaskets on each of the airlock seals.

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APPLICABLE SAFETY ANALYSES (continued)

Air lock operability does not require pressurization of the air lock door seals except as needed to verify the seals have reseated after each air lock door is operated (see LCO 3.6.2, "Containment Air Locks"). <u>For loss of WC&PPS pressurization</u>, isolation of the WC&PPS supply to the affected air lock door seals provides appropriate compensatory action because pressurization is not required for air lock operability (except as needed to verify the seals have reseated after each air lock door is operated) and isolating the depressurized WC&PPS supply eliminates WC&PPS as a potential leakage path. <u>For high WC&PPS air consumption</u>, a consideration is that the leakage may indicate that a supported air lock seal is exceeding its leakage rate acceptance criteria. If the leakage path is isolated from the supported air lock when the WC&PPS supply to the air lock is isolated, isolation of the WC&PPS supply to the air lock restores the required safety function. If the leakage path is not isolated from the supported air lock seal when the WC&PPS supply to the air lock seal is isolated, the supported air lock may be inoperable and the requirements of LCO 3.6.2, "Containment Air Locks," are applicable.

<u>For weld channels and piping penetrations supported by WC&PPS</u>, WC&PPS pressurizes what is equivalent to a closed system inside containment. Because it is reasonable to assume that WC&PPS leakage is not the result of a containment weld or piping penetration defect, WC&PPS leakage and/or lack of pressurization is a concern only because it presents a potential leakage path from containment to the atmosphere via the depressurized WC&PPS. Therefore, isolation of the WC&PPS supply to the affected section of weld channel or piping penetration provides appropriate compensatory action for both loss of pressurization and air consumption caused by flow from the WC&PPS into containment. This assumes that containment leakage rate testing required by Specification 5.15 provides a high degree of assurance that WC&PPS air consumption is not indicative of deterioration of the containment boundary.

WC&PPS satisfies Criterion 3 of 10 CFR 50.36 where it is used to pressurize the space between selected CIVs and pressurize air

(continued)

APPLICABLE SAFETY ANALYSES (continued)

lock door seals. The WC&PPS system, if not maintained at the required pressure, represents a potential leakage path to the environment if there is a single failure of a supported CIV or air lock seal.

WC&PPS satisfies Criterion 4 of 10 CFR 50.36 it provides an additional means for ensuring that containment leakage is minimized although no credit is taken for the WC&PPS in calculating offsite dose for meeting 10 CFR 100 and GDC 19.

LCO

This LCO requires that the WC&PPS be OPERABLE. OPERABILITY requires the following: all required portions of each WC&PPS zone are pressurized to a value that exceeds peak containment pressure during a design basis accident; and, total leakage (i.e., air consumption) from the required portions of the WC&PPS are within specified limits. Limits for air consumption are based on the integrated containment leak rate test acceptance criterion and the ability of the reserve air supplies in the air receivers and nitrogen cylinders to maintain WC&PPS pressure above calculated containment pressure for a minimum of 24 hours following an event. Station Air is not credited for air supply to the WC&PPS during an event.

For a portion of the WC&PPS to be considered not required, it must meet all of the following criteria: 1) it must be inoperable (i.e., can not maintain a pressure above required limits and/or cause system air consumption to exceed required limits); 2) it must be isolated or disconnected from the system; and, 3) it must have been determined by written evaluation as not practicably accessible for repair.

Inoperable sections of WC&PPS piping which can be considered as not practicably accessible for repair will satisfy one of the following criteria: 1) the piping is covered by concrete and repairs of the piping would involve the removal of some portion of the containment structure; or, 2) the piping is located behind plant equipment in the containment building and repairs of the piping would involve the relocation of the equipment.

(continued)

BASES

LCO (continued)

The integrity of the welds associated with any disconnected or isolated portions of the WC&PPS is considered verified by integrated leak rate testing performed in accordance with Specification 5.15. The provision that allows for the disconnection of portions of the WC&PPS piping does not apply to any other WC&PPS piping.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. WC&PPS is required to support OPERABILITY of the containment, containment air locks, and selected containment isolation valves. In MODES 5 and 6, OPERABILITY of the containment, containment air locks, and containment isolation valves is not required. Therefore, the WC&PPS is not required to be OPERABLE in MODES 5 and 6.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 is added to clarify that Separate Condition entry is allowed for each component supplied by WC&PPS. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each component supported by WC&PPS. Complying with the Required Actions may allow for continued operation, and subsequent inoperable WC&PPS components are governed by subsequent Condition entry and application of associated Required Actions.

Note 2 is added to direct entry into the applicable Conditions and Required Actions of LCO 3.6.1, “Containment,” if it is determined that WC&PPS inoperability is indicative of exceeding the overall containment leakage rate. Note that entry into the Conditions and Required Actions of LCO 3.6.1 may be required even if WC&PPS air consumption limits are not exceeded.

A.1 and A.2

In the event one or more components supplied by WC&PPS is not within the pressure limit of SR 3.6.10.1, Required Action A.1 requires that the WC&PPS supply to the affected weld channels, penetrations, or containment isolation valves must be isolated within 4 hours. Required Action A.1 is needed because isolation of the WC&PPS

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

supply to the affected component results in using an isolation valve as a substitute for pressurization. This prevents the WC&PPS from becoming a potential leakage path from the containment to the atmosphere. This action satisfies the required safety function because the leakage rate testing performed in accordance with Specification 5.15 has already verified that the containment leakage rate is within required limits without crediting the WC&PPS.

The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange (including Swagelok fittings), and a check valve with flow through the valve secured (Ref. 3). For a WC&PPS supply isolated in accordance with Required Action A.1, the device used to isolate the weld channel, penetration or containment isolation valves should be the closest available to component. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

If a WC&PPS supply cannot be restored to OPERABLE status within the 4 hour Completion Time and is isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and not pressurized by WC&PPS will be in the isolation position should an event occur. Required Action A.2 does not require any testing or device manipulation. This action involves verification, through a system walkdown, that isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" and exempting valves that are locked, sealed or otherwise secured in the required position is appropriate considering the fact that the devices are operated under administrative controls and the

(continued)

ACTIONS

A.1 and A.2 (continued)

probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these devices, once they have been verified to be in the proper position, is small.

B.1, B.2 and B.3

Condition B applies if WC&PPS has air consumption that places the WC&PPS outside the limits of SR 3.6.10.2. This also applies if the air receivers or nitrogen cylinders necessary to maintain WC&PPS pressure above calculated containment pressure for a minimum of 24 hours following a design basis event are unavailable. In this condition, Required Action B.3 requires that portions of the WC&PPS are isolated, as necessary, to restore WC&PPS leakage to within the limits of SR 3.6.10.2. However, safety function is not restored until any portions of the WC&PPS that are depressurized by this Action are isolated. Therefore, Required Action B.3, is modified by a Note that requires entry into Condition A for components not within the pressure limit of SR 3.6.10.1 as a result of isolating the leakage path. The Completion Time of 7 days to isolate the leakage path is acceptable because all un-isolated portions of the WC&PPS are pressurized, otherwise, Condition A is applicable immediately. Safety function is restored when leaking portions of the WC&PPS are isolated and at least one isolation device separates the containment barrier from the WC&PPS leakage path. If leakage exceeds 0.2%, then replenishment would be required before 24 hours, during an accident.

(continued)

ACTIONS

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

As discussed in the Applicable Safety Analyses above, safety function is not restored by Required Action B.3 if the air consumption leakage path is depressurized but not isolated from the supported containment isolation valves or containment air lock seal. In this situation, the WC&PPS air consumption leakage path could create a leakage path from containment to the atmosphere. Therefore, Required Action B.1 requires entry into the applicable Conditions and Required Actions of LCO 3.6.3, "Containment Isolation Valves" within 1 hour of discovery that the WC&PPS air consumption leakage path is depressurized and not isolated from the supported containment isolation valves. Likewise, Required Action B.2 requires entry into the applicable Conditions and Required Actions of LCO 3.6.2, "Containment Air Locks" within 1 hour of discovery that the WC&PPS air consumption leakage path is depressurized and not isolated from the supported air locks. The Required Actions of LCO 3.6.2 and LCO 3.6.3 will restore safety function for WC&PPS air consumption leakage path that is depressurized.

C.1 and C.2

If the Required Actions and associated Completion Times 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 6 hours and to MODE 5 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 3.6.10.1

This SR requires periodic verification during plant operation that the required portions of each WC& PPS zone are maintained at a pressure greater than the containment peak accident pressure.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.10.1 (continued)

This SR is satisfied by verification of zone pressure on each of the four WC&PPS zones is above the specified limit. The 31 day Frequency is acceptable because there are low pressure alarms in the Control Room to ensure that operators are aware that all WC&PPS zones are pressurized.

SR 3.6.10.2

This SR requires periodic verification during plant operation that the WC&PPS air consumption is $\leq$ 0.2% of the containment free volume per day. This SR is performed by taking the sum of the reading on the flow sensing devices located in each of the zone headers. A WC&PPS flow rate of 14.2 scfm, if sustained for 24 hours, is equivalent to 0.2% of the containment free volume at a pressure of 43 psig. The 31 day Frequency recognizes that WC&PPS air consumption indication and high flow alarms are provided in the control room.

SR 3.6.10.3

This SR, sometimes called the sensitive leak rate test, ensures that the leakage rate for the WC&PPS is $\leq$ 0.2% of the containment free volume per day when pressurized to $\geq$ 43 psig above containment pressure. The sensitive leak rate test includes only the volume of the weld channels, double penetrations, and containment isolation valves supported by WC&PPS. This test is considered more sensitive than the integrated leakage rate test, as the instrumentation used permits a direct measurement of leakage from the pressurized zones. The 36 month Frequency is acceptable because experience has shown that the WC&PPS usually passes this Surveillance when performed at the 36 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The Frequency is modified by a Note indicating that SR 3.0.2 is not applicable.

(continued)

BASES

REFERENCES

1. FSAR, Section 6.6.
2. Safety Evaluation Report for IP3 Amendment 174.
3. FSAR, Section 14.3.
4. Standard Review Plan Section 6.2.4.

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND

The primary purpose of the MSSVs is to provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser and Circulating Water System, is not available.

Five MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves and non-return valves, as described in the FSAR, Section 10.2 (Ref. 1). The five code safety valves per steam generator consist of four 6 inch by 10 inch and one 6 inch by 8 in. These valves are set to open at 1065, 1080, 1095, 1110 and 1120 psig, respectively. The steam generator safety valve capacity is rated to remove the maximum calculated steam flow (normally 105% of the maximum guaranteed steam flow) from the steam generators without exceeding 110% of the steam system design pressure, (Ref. 2). The MSSV design includes staggered setpoints, according to Table 3.7.1-2 in the accompanying LCO, so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open all valves following a turbine or reactor trip.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from Reference 2 and its purpose is to limit the secondary system pressure to 110% of design pressure when passing 100% of design steam flow. This design basis is sufficient to cope with any anticipated operational occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The events that challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat removal events, which are presented in the FSAR, Section 14 (Ref. 3). Of these, the full power loss of external electrical load without steam dump is the limiting AOO.

The transient response for loss of external electrical load without a direct reactor trip presents no hazard to the integrity of the RCS or the Main Steam System. If a minimum reactivity feedback is assumed, the reactor is tripped on high pressurizer pressure. In this case, the pressurizer safety valves open, and RCS pressure remains below 110% of the design value. The MSSVs also open to limit the secondary steam pressure.

If maximum reactivity feedback is assumed, the reactor is tripped on overtemperature ΔT. The departure from nucleate boiling ratio increases throughout the transient, and never drops below its initial value. Pressurizer relief valves and MSSVs are activated and prevent overpressurization in the primary and secondary systems.

Startup and power operation with less than all five MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is proportionally limited to the relief capacity of the remaining MSSVs. This is accomplished by reducing the neutron flux trip setpoint and reducing THERMAL POWER so that the energy transfer to the most limiting steam generator is not greater than the available relief capacity in that steam generator. These limits on the neutron flux trip setpoint, specified in Table 3.7.1-1, are established based on guidance provided in Nuclear Safety Advisory Letter (NSAL) 94-001, Operation at Reduced Power Levels with Inoperable Main Steam Safety Valves (Ref. 6) and Information Notice 94-60, Potential Overpressurization of Main Steam System (Ref. 7). The reactor trip setpoint reductions are calculated as follows:

$$HiQ = (100 / Q)\ [(w s h_{fg} N) / K]$$

Where:

HiQ = Safety Analysis high neutron flux setpoint (% RTP);

(continued)

APPLICABLE SAFETY ANALYSES (continued)

Q = Nominal NSSS power rating of the plant (including reactor coolant pump heat) in Mwt (i.e., 3230 Mwt);

K = Conversion factor, 947.82 (Btu/sec)/Mwt;

ws = Minimum total steam flow rate capability of the operable MSSVs on any one steam generator at the highest MSSV opening pressure, including tolerance and accumulation, as appropriate, in lb/sec. (ws = 150 + 228.61 * (4 - V) lb/sec, where V = Number of inoperable safety valves in the steam line of the most limiting steam generator).

h_{fg} = Heat of vaporization for steam at the highest MSSV opening pressure including tolerance and accumulation, as appropriate, Btu/lbm (i.e.,608.5 Btu/lbm).

N = Number of loops in plant (i.e., 4).

The calculated reactor trip setpoint is further reduced by 9% of full scale to account for instrument uncertainty and then rounded down.

The MSSVs satisfy Criterion 3 of 10 CFR 50.36.

LCO

The accident analysis requires five MSSVs per steam generator to provide overpressure protection for design basis transients occurring at 102% RTP. An MSSV will be considered inoperable if it fails to open on demand. The LCO requires that five MSSVs be OPERABLE in compliance with Reference 2. This is because operation with less than the full number of MSSVs requires limitations on allowable THERMAL POWER (to meet ASME Code requirements). These limitations are according to Table 3.7.1-1 in the accompanying LCO, and Required Action A.1.

The OPERABILITY of the MSSVs is defined as the ability to open within the setpoint tolerances, relieve steam generator overpressure, and reseat when pressure has been reduced.

(continued)

LCO (continued)

The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

The lift settings, according to Table 3.7.1-2 in the accompanying LCO, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB.

APPLICABILITY

In MODE 1 above 20% RTP, the number of MSSVs per steam generator required to be OPERABLE must be according to Table 3.7.1-1 in the accompanying LCO. Below 20% RTP in MODES 1, 2, and 3, only two MSSVs per steam generator are required to be OPERABLE.

In MODES 4 and 5, there are no credible transients requiring the MSSVs. The steam generators are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

A.1

Startup and power operation with up to three of the five MSSVs associated with each steam generator inoperable is permissible if the maximum allowed power level is below the heat removing capability of the operable MSSVs. Therefore, startup and power operation with inoperable main steam line safety valves is allowable if the neutron flux trip setpoints are restricted within the limits specified in Table 3.7.1-1. This ensures that reactor power level is limited so that the heat input from the primary side will not exceed the heat removing capability of the OPERABLE MSSVs of the most limiting steam generator.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the MSSVs cannot be restored to OPERABLE status within the associated Completion Time, or if one or more steam generators have less than two MSSVs OPERABLE, 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 6 hours, and in MODE 4 within 12 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 the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code (Ref. 4), requires that safety and relief valve tests be performed in accordance with ANSI/ASME OM-1-1987 (Ref. 5). According to Reference 5, the following tests are required:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting); and

d. Compliance with owner's seat tightness criteria.

The ANSI/ASME Standard requires that all valves be tested every 5 years, and a minimum of 20% of the valves be tested every 24 months. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-2 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

REFERENCES

1. FSAR, Section 10.2.
2. ASME, Boiler and Pressure Vessel Code, Section III, 1971 Edition.
3. FSAR, Section 14.
4. ASME code for Operation and Maintenance of Nuclear Power Plants.
5. ANSI/ASME OM-1-1987.
6. Nuclear Safety Advisory Letter (NSAL) 94-001, Operation at Reduced Power Levels with Inoperable Main Steam Safety Valves.
7. Information Notice 94-60, Potential Overpressurization of Main Steam System.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs) and Main Steam Check Valves (MSCVs)

BASES

BACKGROUND

The Main Steam System conducts steam from each of the four steam generators within the containment building to the turbine stop and control valves. The four steam lines are interconnected near the turbine. Each steam line is equipped with an isolation valve identified as the Main Steam Isolation Valve (MSIV) and a non-return valve identified as the Main Steam Check Valve (MSCV).

The MSIVs isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators.

The MSIVs are swing disc type check valves that are aligned to prevent flow out of the steam generator. During normal operation, the free swinging discs in the MSIVs are held out of the main steam flow path by an air piston and the MSIVs close to prevent the release of steam from the SG when air is removed from the piston. The isolation valves are designed to and required to close in less than five seconds. The MSIV operators are supplied by instrument air and each MSIV is equipped with an air receiver to prevent spurious MSIV closure due to pressure transients in the instrument air system.

Each MSIV is equipped with a bypass valve used to warm up the steam line during unit startup which equalizes pressure across the valve allowing it to be opened. The bypass valves are manually operated and are closed during normal plant operation.

An MSIV closure signal is generated by the following signals:

> High steam flow in any two out of the four steam lines coincident with low steam line pressure; or,
>
> High steam flow in any two out of the four steam lines coincident with low Tavg; or,

(continued)

BASES

BACKGROUND (continued)

Two sets of the two-of-three high-high containment pressure signals; or,

Manual actuation using a separate switch in the control room for each MSIV.

Note that a turbine trip is initiated whenever an MSIV is not fully open.

The MSCVs are swing disc type check valves that are aligned to prevent reverse flow of steam into an SG if an individual SG pressure falls below steamline pressure.

One MSIV and one MSCV are located in each main steam line outside but close to containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply to prevent MSSV and AFW isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the others, and isolates the turbine, Steam Bypass System (High Pressure Steam Dump), and other auxiliary steam supplies from the steam generators.

A description of the MSIVs and MSCVs is found in the FSAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment (Ref. 2) and the accident analysis of the SLB events presented in the FSAR, Sections 6.2 and 14.2 (References 2 and 3, respectively). The combination of MSIVs and MSCVs precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand). For a break upstream of an MSIV, either the MSIVs in the other three steam lines or the MSCV in the steam line with the faulted SG must close to prevent the blowdown of more than one SG. For a break downstream of an MSIV, the MSCVs are not required to function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting case for the containment analysis is the SLB inside containment, without a loss of offsite power and failure to close of the MSCV on the affected steam generator or the failure to close of the MSIV associated with any other SG. With either of these failures, only one SG blows down.

The limiting SLBs occur at low power or hot shutdown because the magnitude and duration of the RCS cooldown will be greater if the SLB is initiated from these conditions. This occurs because, at low power conditions, there is less stored energy in the fuel and the initial steam generator water inventory is greatest at no load. Additionally, the magnitude and duration of the RCS cooldown will be greater if RCPs continue to operate during the SLB. Therefore, an SLB without loss of offsite power is more limiting.

If it is assumed that the most reactive rod cluster control assembly is stuck in the fully withdrawn position, there is an increased possibility that the core will become critical and return to power. In the most limiting condition, the core is ultimately shut down by the boric acid injection delivered by the Emergency Core Cooling System.

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB inside containment at hot zero power with offsite power available is the limiting case for a post trip return to power. The analysis includes scenarios with offsite power available, and with a loss of offsite power following turbine trip. With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System cooldown. With a loss of offsite power, the response of mitigating systems is delayed.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Significant single failures considered include: 1) failure of an MSIV or MSCV to close; 2) failure of a feedwater control or isolation valve to close; 3) failure of a diesel generator; and, 4) failure of auxiliary feedwater pump runout protection.

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. A HELB inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the MSCV in the affected steam generator remains open. For this accident scenario, steam is discharged into containment from all steam generators until the remaining MSIVs close. After MSIV closure, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIVs in the unaffected loops. Closure of the MSIVs isolates the break from the unaffected steam generators.

b. A break outside of containment and upstream from the MSIVs. This case is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs isolates the break and limits the blowdown to a single steam generator.

c. A break downstream of the MSIVs. This case will be isolated by the closure of the MSIVs.

d. Following a steam generator tube rupture. In this case, closure of the MSIVs isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

e. The MSIVs are also utilized during other events such as a feedwater line break. This event is less limiting so far as MSIV OPERABILITY is concerned.

The MSIVs satisfy Criterion 3 of 10 CFR 50.36.

LCO

This LCO requires that four MSIVs and four MSCVs in the steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal. The MSCVs are considered OPERABLE when inspections and testing required by the Inservice Test Program are completed at the specified FREQUENCY in accordance with SR 3.7.2.2.

This LCO provides assurance that the MSIVs and MSCVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 50.67 (Ref. 4) limits or the NRC staff approved licensing basis.

APPLICABILITY

The MSIVs and MSCVs must be OPERABLE in MODE 1, and in MODES 2 and 3 except when MSIVs are closed. These are the conditions when there is significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function.

In MODE 4, the steam generator energy is low and the potential for and consequences of an SLB are significantly reduced. In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

(continued)

BASES

ACTIONS

A.1

With one or more MSCVs inoperable, action must be taken to restore OPERABLE status within 48 hours. In this condition, the MSIVs in the other three steam lines must close to prevent the blowdown of more than one SG following an SLB upstream of an MSIV. Having more than one MSCV inoperable will not increase the consequences of an SLB upstream of an MSIV because only the MSCV associated with the faulted SG needs to function to mitigate the failure of an MSIV associated with any of the other SGs. Additionally, an inoperable MSCV does not affect the consequences of an SLB downstream of the MSIV.

The 48 hour Completion Time is acceptable because of the following: all MSIVs are Operable, there is a low probability of the failure of an MSIV during the 48 hour period that one or more MSCVs are inoperable; and, there is a low probability of an accident that would require a closure of the MSCVs or MSIVs during this period.

B.1, B.2 and B.3

If the MSCVs cannot be restored to OPERABLE status within 48 hours, 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 MODE 2 within 6 hours and all MSIVs must be closed within 14 hours. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs or complete a plant cooldown to MODE 4 in an orderly manner and without challenging unit systems.
If an inoperable MSCVs cannot be restored to OPERABLE status within the specified Completion Time, then all MSIVs must be verified to be closed on a periodic basis while the plant is in MODE 2 or 3. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

(continued)

BASES

ACTIONS (continued)

C.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 48 hours. Some repairs to the MSIV can be made with the unit hot. The 48 hour Completion Time is acceptable because the four OPERABLE MSCVs prevent the blowdown of more than one SG following an SLB upstream of the MSIV even if more than one MSIV fails to close. Additionally, there is a low probability of the failure of an MSCV during the 48 hour period that the MSIV is inoperable; and, there is a low probability of an accident that would require a closure of the MSIVs occurring during this time period.

The 48 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from most other containment isolation valves in that the closed system provides an additional means for containment isolation.

D.1

If the MSIV cannot be restored to OPERABLE status within 48 hours, 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 MODE 2 within 6 hours and Condition E would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

E.1 and E.2

Condition E is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

(continued)

ACTIONS

E.1 and E.2 (continued)

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is reasonable, based on operating experience, to close the MSIVs after reaching MODE 2 or complete a plant cooldown to MODE 4 in an orderly manner and without challenging unit systems.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

F.1 and F.2

If one MSIV is inoperable when one or more MSCVs are inoperable, then more than one SG may blowdown following an SLB upstream of an MSIV and the plant is outside of the analysis assumptions. The plant remains within the analysis assumptions for an SLB downstream of an MSIV although the ability to tolerate the failure of a second MSIV is lost. In this condition, all MSCVs must be restored to OPERABLE status or all MSIVs must be restored to OPERABLE status within 8 hours.

The 8 hour Completion Time is acceptable because of the low probability of an accident that would require a closure of the MSCVs or MSIVs during this time period. The 8 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a closed system penetrating Containment. These valves differ from most other containment isolation valves in that the closed system provides an additional means for containment isolation.

(continued)

BASES

ACTIONS

G.1 and G.2

If the MSIVs or MSCVs cannot be restored to OPERABLE status or are not closed within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is $\leq$ 5.0 seconds on an actual or simulated actuation signal. The MSIV closure time is assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. The MSIVs are not tested at power because even a part stroke causes a turbine trip and valve closure. As the MSIVs are not tested at power, they are exempt from the ASME Code (Ref. 5), requirements during operation in MODE 1 or 2.

The Frequency is in accordance with the Inservice Testing Program.

This test is conducted in MODE 3 with the unit at operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.2.2

Each MSCV must be inspected to ensure that it closes properly. This ensures that the safety analysis assumptions are met. The Frequency of this SR is based on Inservice Testing Program requirements and corresponds to the expected refueling cycle.

REFERENCES

1. FSAR, Section 10.2.
2. FSAR, Section 6.
3. FSAR, Section 14.
4. 10 CFR 50.67.
5. ASME code for Operation and Maintenance of Nuclear Power Plants

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Boiler Feedpump Discharge Valves (MBFPDVs), Main Feedwater Regulation Valves (MFRVs), Main Feedwater Inlet Isolation Valves (MFIIVs) and Main Feedwater (MF) Low Flow Bypass Valves

BASES

BACKGROUND

The MFIIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). The safety related function of the MFRVs is to provide the second isolation of MFW flow to the secondary side of the steam generators following an HELB. Closure of the MFIIVs or MFRVs and associated low flow bypass valves terminates flow to the steam generators. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MFIIVs will be mitigated by their closure. Closure of the MFIIVs or MFRVs and associated low flow bypass valves, effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs.

In the event of a secondary side pipe rupture inside containment, either the MFIIVs or MFRVs and associated MF low flow bypass valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact loops.

One MFIIV and one MFRV are located on each of the four MFW lines, outside but close to containment. Two MF low flow bypass valves, in series, are located on a six inch line that bypasses both the MFIIV and MFRV. Each valve is associated with the valve having the same power train. The MFIVs and MFRVs are located upstream of the AFW injection point so that AFW may be supplied to the steam generators following MBFPDV, MFIIV or MFRV closure. The piping volume from these valves to the steam generators must be accounted for in calculating mass and energy releases, and refilled prior to AFW reaching the steam generator following either an SLB or FWLB.

(continued)

BASES

BACKGROUND (continued)

The MBFPDVs, MFIIVs, MFRVs and associated low flow bypass valves will close on receipt of an ESFAS Safety Injection signal. An ESFAS Tavg—Low coincident with reactor trip will close the MFRVs and associated MF low flow bypass valves. A Steam Generator Hi-Hi level trip will close both MBFPDVs and the MFRVs and associated MF low flow bypass valves associated with the affected SG. They may also be closed manually. In addition to the two MBFPDVs, four MFRVs, four MFIIVs and eight MF low flow bypass valves, a check valve outside containment is available. The check valve isolates the feedwater line to prevent blowdown of a SG if main or auxiliary feedwater pressure are lost.

A description of the MBFPDVs and MFRVs is found in the FSAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MFIIVs and MFRVs is established by the analyses for the large SLB. Closure of the MFIIVs, MFRVs and MF low flow bypass valves, may also be relied on to terminate an SLB for core response analysis. Closure of the MBFPDVs, MFRVs and the associated MF low flow bypass valves may be relied upon to terminate an excess feedwater event upon the receipt of a steam generator water level—high high or a feedwater isolation signal. Feedwater isolation also occurs as a result of any safety injection signal. Failure of an MFIIV in conjunction with the failure of an MFRV or failure of two MF low flow bypass valves to close following an SLB can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an SLB or FWLB event.

The MBFPDVs, MFIIVs, MFRVs and MF Low Flow Bypass Valves satisfy Criterion 3 of 10 CFR 50.36.

LCO

This LCO ensures that the MBFPDVs, MFIIVs, MFRVs and MF low flow bypass valves will isolate MFW flow to the steam generators, following a main steam line break or excess feedwater event.

(continued)

BASES

LCO (continued)

This LCO requires that two MBFPDVs, four MFIIVs, four MFRVs and eight MF low flow bypass valves be OPERABLE. The MBFPDVs, MFRVs and MF low flow bypass valves are considered OPERABLE when isolation times are within limits and they close on an isolation actuation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FWLB inside containment. A feedwater isolation signal on a steam generator water level—high high signal and this function is relied on to terminate an excess feedwater flow event; therefore, failure to meet the LCO may result in the introduction of water into the main steam lines.

APPLICABILITY

The MFIIVs, MFRVs and MF bypass valves must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and steam generators. This ensures that, in the event of an HELB, a single failure cannot result in the blowdown of more than one steam generator. In MODES 1, 2, and 3, the MBFPDVs, MFIIVs, MFRVs and MF bypass valves are required to be OPERABLE to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment and to limit feedwater in an excess feedwater event. When the valves are closed and de-activated or isolated by a closed manual valve, they are already performing their safety function. A de-activated motor operated valve is considered to be a manual valve.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, the MBFPDVs, MFIIVs, MFRVs and MF bypass valves are normally closed since MFW is not required.

ACTIONS The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each valve.

A.1 and A.2

With one MFPDV in one or both flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves, the MBFP trip function, and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on industry operating experience.

Inoperable MBFPDVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7-day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

B.1 and B.2

With one MFRV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on industry operating experience.

Inoperable MFRVs, that are closed or isolated, must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of other administrative controls to ensure that the valves are closed or isolated.

(continued)

ACTIONS (continued)

C.1 and C.2

With one MFIIV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on industry operating experience.

Inoperable MFIIVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of the administrative controls that ensure that these valves are closed or isolated.

D.1 and D.2

With one MF low flow bypass valve in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on industry operating experience.

Inoperable associated bypass valves that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of the administrative controls that ensure that these valves are closed or isolated.

(continued)

BASES

ACTIONS (continued)

E.1

With two inoperable valves in series in the same flow path, there may be no redundant system to operate automatically and perform the required safety function. Under these conditions, affected valves in each flow path must be restored to OPERABLE status, or the affected flow path isolated within 8 hours. This action returns the system to the condition where at least one valve in each flow path is performing the required safety function. The 8 hour Completion Time is reasonable, based on operating experience, to complete the actions required to close the MBFPDV, MFIIV, or MFRV, or otherwise isolate the affected flow path.

F.1 and F.2

If the MBFPDV(s), MFIIVs, MFRV(s), and MF low flow bypass valve(s) cannot be restored to OPERABLE status, or closed, or isolated within the associated Completion Time, 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 6 hours, and in MODE 4 within 12 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 3.7.3.1

This SR verifies that the closure time of each MBFPDV(s), MFIIV(s), MFRV(s), and MF low flow bypass valves is within required limits on an actual or simulated actuation signal. The primary MF low flow bypass valves, associated with MFRVs, are FCVs 417L, 427L, 437L and 447L. The backup low flow bypass valves, associated with MFIIVs, are 90-1, 90-2, 90-3, and 90-4. The closure times are assumed in the accident and containment analyses. The acceptance criteria for this SR do not include the 2 second delay associated with the ESFAS activation signal. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. The MBFPDVs, MFIIVs and MFRVs can not be tested at power because valve closure or even a

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1 (continued)

part stroke exercise increases the risk of a valve closure and MBFP trip. The MF low flow bypass valves are normally closed during power operation and do not require testing. This is consistent with the ASME Code (Ref. 2), quarterly stroke requirements during operation in MODES 1 and 2.

The Frequency for this SR is in accordance with the Inservice Testing Program. The required Frequency for valve closure is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the required Frequency.

REFERENCES

1. FSAR, Section 10.2.

2. ASME code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.4 Atmospheric Dump Valves (ADVs)

BASES

BACKGROUND

The ADVs provide a method for cooling the unit to residual heat removal (RHR) entry conditions should the preferred heat sink via the Steam Bypass System (High Pressure Steam Dump) to the condenser not be available, as discussed in the FSAR, Section 10.2 (Ref. 1). This is done in conjunction with the Auxiliary Feedwater System providing cooling water from the condensate storage tank (CST). The ADVs may also be required to meet the design cooldown rate during a normal cooldown when steam pressure drops too low for maintenance of a vacuum in the condenser to permit use of the High Pressure Steam Dump System.

One ADV line for each of the four steam generators is provided. Each ADV line consists of one ADV and an associated manually operated block valve.

The block valves are upstream of the ADVs to permit testing and maintenance at power, and to provide an alternate means of isolation. The ADVs are equipped with pneumatic controllers to permit control of the cooldown rate.

The ADVs are provided with a pressurized gas supply of bottled nitrogen that is needed to support manual operation of the atmospheric dump valves. The nitrogen supply is sized to provide the sufficient pressurized gas to operate the ADVs for the time required for Reactor Coolant System cooldown to RHR entry conditions.

A description of the ADVs is found in Reference 1.

APPLICABLE SAFETY ANALYSES

The design basis of the ADVs is established by the capability to cool the unit to RHR entry conditions. The total relief capacity of the four ADVs is approximately 10% of the rated steam flow.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

This is adequate to cool the unit to RHR entry conditions with only one steam generator and one ADV, utilizing the cooling water supply available in the CST.

In the accident analysis presented in Reference 2, the ADVs are assumed to be used by the operator to cool down the unit to RHR entry conditions for accidents accompanied by a loss of offsite power. Prior to operator actions to cool down the unit, the main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the steam generator pressure below the design value. For the recovery from a steam generator tube rupture (SGTR) event, the operator is also required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the ruptured steam generator. The time required to terminate the primary to secondary break flow for an SGTR is more critical than the time required to cool down to RHR conditions for this event and also for other accidents. Thus, the SGTR is the limiting event for the ADVs. The requirement that 4 ADVs must be OPERABLE is established to ensure that at least three ADV lines are available under local or remote control to conduct a plant cooldown following an event in which one steam generator becomes unavailable due to the event (i.e., SGTR). No failure of a second ADV line on an unaffected steam generator is postulated.

The ADVs are equipped with block valves in the event an ADV spuriously fails open or fails to close during use.

The ADVs satisfy Criterion 3 of 10 CFR 50.36.

LCO

Four ADV lines are required to be OPERABLE. One ADV line is required from each of four steam generators to ensure that at least three ADV lines are available to conduct a unit cooldown following an SGTR, in which one steam generator becomes unavailable and no failure of a second ADV line on an unaffected steam generator is postulated. The block valves must be OPERABLE to isolate a failed open ADV line. A closed block valve does not render it or its ADV line inoperable because operator action time to open the block valve is supported in the accident analysis.

(continued)

BASES

LCO (continued)

Failure to meet the LCO can result in the inability to cool the unit to RHR entry conditions following an event in which the condenser is unavailable for use with the Turbine Steam Bypass System (High Pressure Steam Dump).

An ADV is considered OPERABLE when it is capable of providing controlled relief of the main steam flow and capable of fully opening and closing on demand (either remotely or under local control).

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when a steam generator is being relied upon for heat removal, the ADVs are required to be OPERABLE.

In MODE 5 or 6, an SGTR is not a credible event.

ACTIONS

A.1

With one required ADV line inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time allows for the capability afforded by the remaining OPERABLE ADV lines. Specifically, with one of the four required ADVs inoperable, at least two ADV lines are available to conduct a plant cooldown following an event in which one steam generator becomes unavailable due to the event (i.e., SGTR). Also available are a nonsafety grade backup in the Steam Bypass System, and the safety related MSSVs. Additionally, the substantial margin between the SGTR analysis results and the Reference 3 dose acceptance limits supports a conclusion that the limits would be met if an inoperable ADV increases the time required to equalize pressure between the RCS and the ruptured SG following a SGTR.

B.1

With two or more required ADV lines inoperable, action must be taken to restore all but one ADV line to OPERABLE status. Since the block valve can be closed to isolate an ADV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable ADV lines, based on the availability of the Steam Bypass System (HP Steam Dump) and MSSVs, and the low probability of an event occurring during this period that would require the ADV lines.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the ADV lines cannot be restored to OPERABLE status within the associated Completion Time, 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 6 hours, and in MODE 4, without reliance upon steam generator for heat removal, within 18 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 3.7.4.1

To perform a controlled cooldown of the RCS, the ADVs must be able to be opened either remotely or locally and throttled through their full range. This SR ensures that the ADVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of an ADV during a unit cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the specified Frequency and, therefore, is acceptable from a reliability standpoint.

SR 3.7.4.2

The function of the block valve is to isolate a failed open ADV. Cycling the block valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the block valve during unit cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the specified Frequency and, therefore, is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 10.2.
2. FSAR, Section 14.2.4.
3. NUREG-0800, Standard Review Plan, US Nuclear Regulatory Commission, Section 15.0.1, “Radiological Consequences Analysis Using Alternative Source Terms,” Rev. 0, July 2000

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The AFW pumps take suction from the condensate storage tank (CST) (LCO 3.7.6) and pump to the steam generator secondary side via a connection to the main feedwater (MFW) piping at a point outside containment. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1) or atmospheric dump valves (LCO 3.7.4). If the main condenser is available, steam may be released via the steam bypass (High Pressure Steam Dump) valves and recirculated to the CST.

The AFW System consists of two motor driven AFW pumps and one steam turbine driven pump configured into three trains. FSAR Section 10.2 (Ref. 1) describes this configuration as two pumping loops using two different types of motive power to the pumps. One auxiliary feedwater loop utilizes a steam turbine driven pump and the other utilizes two motor driven pumps. Technical specifications describe this configuration as three trains because each motor driven pump provides 100% of AFW flow capacity (near best estimate analysis), and, depending on steam conditions, the turbine driven pump capacity approaches 200% of the required capacity for automatic delivery of AFW to the steam generators, as assumed in the accident analysis. The limiting transient for the AFW System is loss of main feedwater. For this event, the licensing analysis credits 343 gpm delivered automatically to two steam generators and the *minimum* of an additional 343 gpm delivered to the other two steam generators in 10 minutes. A near best estimate analysis has also been performed, and this demonstrated that acceptance criteria are satisfied without assuming additional AFW flow in 10 minutes (Ref. 3). The pumps are equipped with independent recirculation lines to prevent pump operation against a closed system. Each motor driven AFW pump is powered from an independent power supply and feeds two steam generators. The steam turbine driven AFW pump receives steam from two main steam lines upstream of the main steam isolation valves. Each of the steam feed lines will supply 100% of the requirements of the turbine driven AFW pump.

(continued)

BACKGROUND (continued)

The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions.

The turbine driven AFW pump supplies a common header capable of feeding all steam generators. Each of the steam generators can also be supplied by one of the two motor driven AFW pumps. Any of the three pumps at full flow has sufficient capacity such that in the case of complete loss of normal feedwater there is adequate time for operator action to start a second motor driven AFW pump or to align the turbine driven AFW pump to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions. Thus, the requirement for diversity in motive power sources for the AFW System is met.

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the ADVs.

The motor driven pumps are actuated by any one of the following:

1) Low-low level in any steam generator;

2) Loss of voltage (Non SI blackout) on 480 VAC bus 2A/3A (starts AFW Pump 31) and loss of voltage (Non SI blackout) on 480 VAC bus 6A (starts AFW Pump 33);

3) Safety Injection signal;

4) Auto trip of either main boiler feed pump;

5) Manual actuation from the Control Room; and

6) Manual actuation locally at the pump room.

The steam turbine driven pump is actuated by any one of the following:

1) Low-low level in two of the four steam generators;

2) Loss of voltage (Non SI blackout) on 480 VAC busses 2A/3A or 6A;

(continued)

BACKGROUND (continued)

3) Manual actuation from the Control Room; and

4) Manual actuation locally at the pump room.

The steam driven AFW pump must be throttled manually in order to bring the unit up to speed after a start signal. In addition, the steam driven pump discharge flow control valves must be manually opened as necessary to provide adequate auxiliary feedwater flow.

The AFW System is discussed in the FSAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest steam generator safety valve set pressure plus accumulation.

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW System flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting events that require the AFW System are as follows:

a. small break loss of coolant accident;

b. loss of AC sources; and

c. loss of feedwater.

The AFW turbine driven pump actuates automatically when required to ensure an adequate feedwater supply to the steam generators is available during loss of power. Power operated valves are provided for each AFW line to control the AFW flow to each steam generator.

The AFW System satisfies the requirements of Criterion 3 of 10 CFR 50.36.

(continued)

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of events that could result in overpressurization of the reactor coolant pressure boundary. Three independent AFW pumps are required to be OPERABLE to ensure the capability to maintain the plant in hot shutdown with a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.

The AFW System is configured into three trains. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps be OPERABLE, each supplying AFW to two separate steam generators. The turbine driven AFW pump is required to be OPERABLE with steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of supplying AFW to all of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE. Since instrument air cannot be credited for an accident analysis, loss of the nitrogen supply will not allow control room operation. The two motor driven AFW pumps are considered inoperable until local operator action is taken to manually control the pumps. The turbine driven pump can perform its function.

The LCO is modified by a Note indicating that one AFW train, which includes a motor driven pump, is required to be OPERABLE in MODE 4. The motor driven AFW pump required to be OPERABLE in Mode 4 must be capable of supporting the SG(s) being credited as the redundant decay heat removal path in accordance with LCO 3.4.6, RCS Loops - MODE 4. This requirement ensures the ability to maintain the required level in the SG(s) (and decay heat removal capacity) during extended periods in Mode 4 with or without offsite power. Requiring only one OPERABLE AFW pump is acceptable because of the reduced heat removal requirements and short period of time in MODE 4 during which the AFW is required and the insufficient steam available in MODE 4 to power the turbine driven AFW pump.

APPLICABILITY In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory needed to achieve and maintain MODE 4 conditions. In MODE 4, a motor driven AFW pump may be needed to support heat removal via the steam generators. In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

(continued)

BASES

ACTIONS

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

<u>A.1</u>

If one of the two steam supplies to the turbine driven AFW train is inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. The redundant OPERABLE steam supply to the turbine driven AFW pump;

b. The availability of redundant OPERABLE motor driven AFW pumps; and

c. The low probability of an event occurring that requires the inoperable steam supply to the turbine driven AFW pump.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The <u>AND</u> connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

<u>B.1</u>

With one of the required AFW trains (pump or flow path) inoperable in MODE 1, 2, or 3 for reasons other than Condition A, action must be taken to restore OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the AFW System, time needed for repairs, and the low probability of a DBA occurring during this time period.

(continued)

ACTIONS

B.1 (continued)

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 72 hours and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1 and C.2

When Required Action A.1 or B.1 cannot be completed within the required Completion Time, or if two AFW trains are inoperable in MODE 1, 2, or 3, 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 6 hours, and in MODE 4 within 18 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.

In MODE 4 with two AFW trains inoperable, operation is allowed to continue because only one motor driven pump AFW train is required in accordance with the Note that modifies the LCO. Although not required, the unit may continue to cool down and initiate RHR.

D.1

If all three AFW trains are inoperable in MODE 1, 2, or 3, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety related equipment. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one AFW train to OPERABLE status.

(continued)

ACTIONS (continued)

D.1

Required Action D.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AFW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition.

E.1

In MODE 4, either the reactor coolant pumps or the RHR loops can be used to provide forced circulation. This is addressed in LCO 3.4.6, "RCS Loops – MODE 4." With one required AFW train inoperable, action must be taken to immediately restore the inoperable train to OPERABLE status. The immediate Completion Time is consistent with LCO 3.4.6.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the AFW System water and steam supply flow paths provides assurance that the proper flow paths will exist for AFW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

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

This SR is modified by a Note that states the SR is not required in MODE 4. Not performing this SR in MODE 4 is acceptable for the following reasons: AFW pumps are typically operated intermittently to keep the SGs filled when in MODE 4, the decay heat load is low; an RHR loop is required to be OPERABLE as the primary method of decay heat removal in Mode 4; and, the SG is required to be

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.1

maintained at a level that ensures a significant inventory is available as a heat sink before the AFW pump is required to refill the SG. These factors ensure that a significant amount of time would be available to complete any valve realignments needed to refill a SG when in Mode 4.

SR 3.7.5.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by the ASME Code (Ref 2). Because it is undesirable to introduce cold AFW into the steam generators while they are operating, this testing is performed on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing discussed in the ASME Code (Ref. 2) (only required at 3 month intervals) satisfies this requirement.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test when SG pressure is < 600 psig.

SR 3.7.5.3

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an ESFAS, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage (i.e., unit at less than or equal to 97% power and in preparation for main generator breaker opening with no

(continued)

BASES

SURVEILLANCE REQUIREMENTS
(continued)

SR 3.7.5.3

plans to raise power between the time of the surveillance and breaker open) and the potential for an unplanned transient if the Surveillance were performed with the reactor at full power. However, tests that deliver flow are not precluded at power when safety implications are evaluated and the test is needed to show operability of some system components. The 24 month Frequency is acceptable based on operating experience and the design reliability of the equipment.

This SR is modified by a Note that states the SR is not required in MODE 4. In MODE 4, the required AFW train is operated as necessary to maintain SG water level.

SR 3.7.5.4

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal in MODES 1, 2, and 3. In MODE 4, the required pump is operated as necessary and the autostart function is not required. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. However, tests that deliver flow are not precluded at power when safety implications are evaluated and the test is needed to show operability of some system components.

This SR is modified by two Notes. Note 1 indicates that the SR be deferred until suitable test conditions are established. This deferral allows the test to be performed at rated conditions. Note 2 states that the SR is not required in MODE 4. In MODE 4, the required pump is operated as necessary to maintain SG water level and the autostart function is not required. In MODE 4, the heat removal requirements would be less providing more time for operator action to manually start the required AFW pump.

(continued)

BASES

REFERENCES

1. FSAR, Section 10.2.

2. ASME code for Operation and Maintenance of Nuclear Power Plants.

3. Safety Evaluation Report (SER) for IP3 Amendment 225.

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tank (CST)

BASES

BACKGROUND

The CST provides a safety grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CST provides a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.5). The steam produced is released to the atmosphere by the main steam safety valves or the atmospheric dump valves. The AFW steam driven pump operates with a continuous recirculation to the CST. The motor driven AFW pumps have recirculation controllers that recirculate flow to the CST, as necessary, to maintain a minimum required AFW pump flow.

When the main steam isolation valves are open, the preferred means of heat removal is to discharge steam to the condenser by the nonsafety grade path of the steam bypass (High Pressure Steam Dump) valves. The condensed steam is returned to the CST by the condensate pump. This has the advantage of conserving condensate while minimizing releases to the environment.

Because the CST is a principal component in removing residual heat from the RCS, it is designed to withstand earthquakes and other natural phenomena. The CST is designed to Seismic Class I to ensure availability of the auxiliary feedwater supply. Auxiliary feedwater is also available from city water.

The condensate makeup system connects the 600,000 gallon capacity condensate storage tank to the main condenser. The condensate makeup system automatically supplies makeup water from the CST to the condenser if there is a low level in the condenser hotwell. Redundant, safety related, isolating valves will close the condenser makeup when the condensate storage tank level decreases to 360,000 gallons to reserve the required volume of condensate available to the auxiliary feedwater pumps sufficient to hold the plant at hot shutdown for 24 hours following a trip at full power.

(continued)

BASES

BACKGROUND (continued)

To ensure CST pressure is maintained within its design limits while limiting the amount of air in contact with the condensate, two safety related, 100% capacity breather valves are installed on the dome of the CST. CST venting is required for the CST to perform both its normal and emergency function. The venting function can be met by either of the CST breather valves or equivalent venting capacity.

A description of the CST is found in the FSAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The CST provides cooling water to remove decay heat and the minimum amount of water in the condensate storage tank is the amount needed to maintain the plant for 24 hours at hot shutdown following a trip from full power. When the condensate storage tank supply is exhausted, city water will be used.

The CST satisfies Criteria 2 and 3 of 10 CFR 50.36.

LCO

To satisfy accident analysis assumptions, the CST must contain sufficient cooling water to remove decay heat while in MODE 3 for 24 hours following a reactor trip from 102% RTP. In doing this, it must retain sufficient water to ensure adequate net positive suction head for the AFW pumps during cooling, as well as account for any losses from the steam driven AFW pump turbine. When the condensate storage tank supply is exhausted, city water will be used.

The CST level required is equivalent to a total volume of 292,200 gallons, which is based on holding the unit in MODE 3 for 24 hours. This basis is established in Reference 2. The CST total volume includes allowances for instrument accuracy and the unuseable volume in the CST.

(continued)

LCO (continued)

The OPERABILITY of the CST is determined by maintaining the tank level at or above the minimum required level. CST venting and pressure relief capability are required for the CST to perform both its normal and emergency function. The venting and pressure relief functions are satisfied by either of the CST breather valves or equivalent venting capacity.

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when steam generator is being relied upon for heat removal, the CST is required to be OPERABLE.

In MODE 5 or 6, the CST is not required because the AFW System is not required.

ACTIONS

A.1 and A.2

If the CST is not OPERABLE, the OPERABILITY of the backup supply (city water) should be verified by administrative means immediately and once every 12 hours thereafter. OPERABILITY of the backup auxiliary feedwater supply means that LCO 3.7.7, City Water, is met and includes verification that the flow paths from city water to the AFW pumps are OPERABLE. The CST must be restored to OPERABLE status within 7 days. The immediate Completion Time for verification of the OPERABILITY of the backup water supply ensures that Condition B is entered immediately if both the CST and City Water are inoperable. The 7 day Completion Time for restoration of the CST is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the CST.

B.1 and B.2

If the CST cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply.

(continued)

ACTIONS

B.1 and B.2 (continued)

To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance on the steam generator for heat removal, within 18 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.

If Condition B is entered when both the CST and City Water are not Operable, Conditions and Required Actions for LCO 3.7.5, Auxiliary Feedwater System, may be appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that the CST contains the required volume of cooling water. The 12 hour Frequency is based on operating experience and the need for operator awareness of unit evolutions that may affect the CST inventory between checks. Also, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal deviations in the CST level.

REFERENCES

1. FSAR, Section 10.2.

2. WCAP – 16212P, Indian Point Nuclear Power Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report, June 2004.

B 3.7 PLANT SYSTEMS

B 3.7.7 City Water (CW)

BASES

BACKGROUND

City Water is the backup to the Condensate Storage Tank (CST) as a water supply for the Auxiliary Feedwater System. The CST, the preferred source of water for the Steam Generators (SGs), is capable of holding up to 600,000 gallons and is sized to meet the normal operating and maintenance needs of the main steam system. LCO 3.7.6, Condensate Storage Tank, requires that a minimum water level is maintained in the CST that is sufficient to remove residual heat for 24 hours at hot shutdown conditions following a trip from full power. The CST is not designed to withstand the effects of a tornado-generated missile. However, the Auxiliary Feedwater System is provided sufficient redundancy of water supplies such that an alternate source of water from the City Water Tank (CWT) is available in the event the CST is damaged by a tornado-generated missile. Only when the CST supply is exhausted or not available will city water be used to supply the Auxiliary Feedwater System.

When the main steam isolation valves are open, the preferred means of heat removal from the RCS is to discharge steam to the condenser via the non-safety grade turbine steam bypass valves (High Pressure Steam Dump) with water supplied from the CST to the SGs using the AFW System. The condensed steam is returned to the CST by the condensate pump. This configuration conserves condensate and minimizes releases to the environment. The CST is the preferred source of water for the SGs.

When the CST supply is exhausted, city water is used to supply the Auxiliary Feedwater System for decay heat removal and plant cooldown. CW, although aligned to the IP3 site, is normally isolated from the AFW pump suctions.

The City Water System includes the site city water header consisting of the 1.5 million gallon city water storage tank and the connection to the offsite water supply. Reference to the CW system as an alternate supply to the Auxiliary Feedwater is found in FSAR, Section 10 (Ref. 1).

(continued)

APPLICABLE SAFETY ANALYSES

CW can be used to provide cooling water to remove decay heat and to cool down the unit following all events in the accident analysis as discussed in the FSAR; however, it has been established by engineering calculations that 360,000 gallons of water in the CWT is adequate to cooldown the plant from 102% rated thermal power to RHR entry conditions in 10 hours if the CST is not available or depleted. The CST is not designed to withstand the effects of a tornado generated missile and CW is used only when the CST is not available or depleted.

CW satisfies Criterion 3 of 10 CFR 50.36.

LCO

This LCO requires that the CW Tank volume is $\geq$ 360,000 gallons and the isolation valves in the flow path between the CWT and the AFW pumps suction are open. The CWT volume of 360,000 gallons has been determined by calculations to be adequate for a plant cooldown from 102% rated thermal power to RHR entry conditions in 10 hours (Reference 3).

The OPERABILITY of the CW is determined by maintaining the tank volume at or above the minimum required volume and periodic verification that the required lineups can be established.

APPLICABILITY

City Water is required to be OPERABLE in MODES 1, 2, and 3, and in MODE 4, when a steam generator is being relied upon for heat removal. In MODE 5 or 6, CW is not required because the SGs are not normally used to remove decay heat when in these MODES.

ACTIONS

A.1 and A.2

If the CW Tank volume is not within limits or system lineups are not as required, CW cannot be assumed to be available if needed as a backup water source for the CST. With CW not available, OPERABILITY of the CST must be verified by administrative means immediately and once every 12 hours thereafter. Operability of the CST means that LCO 3.7.6, Condensate Storage Tank, is met. The immediate Completion Time for verification of the OPERABILITY of the CST ensures that Condition B is entered immediately if both the CST and

(continued)

ACTIONS

A.1 and A.2 (continued)

City Water are inoperable. This ensures that either the CST or CW is available for decay heat removal and to support a plant cooldown. CW must be restored to OPERABLE status within 7 days because CW is assumed to be available to supply the Auxiliary Feedwater System when the CST supply is exhausted, The 7 day Completion Time for restoration of CW is acceptable because the CST is OPERABLE and the low probability of an event requiring CW during the 7 day Completion Time.

B.1 and B.2

If CW cannot be restored to OPERABLE within the Completion Time, 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 6 hours, and in MODE 4, without reliance on the steam generator for heat removal, within 18 hours. The 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.

If Condition B is entered when both the CST and City Water are not Operable, Conditions and Required Actions for LCO 3.7.5, Auxiliary Feedwater System, may be appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR verifies that the CWT contains a minimum of 360,000 gallons of water. The 24 hour frequency is based on the conditional core damage probability evaluated by Probabilistic Risk Analysis and provides a high degree of assurance of rapid identification of the inoperability of CW.

(continued)

SURVEILLLANCE REQUIREMENTS (continued)

SR 3.7.7.2

This SR verifies that the valves that isolate Unit 3 from the site city water supply and the city water storage tank are open. The Isolation valves are CT-49, in the IP1 Utility Tunnel, (also identified as valve FP-1227), CT-1300 and CT-1302. SR for CT-49 may be performed by Unit 2 personnel. The 31 day Frequency is acceptable because the valves are sealed open and because periodic verification provided by SR 3.7.7.2 provides a high degree of assurance that the valves are positioned properly.

SR 3.7.7.3

This SR verifies the ability to cycle each valve between CW and the AFW pump suction. These are the only valves required to operate to align CW to the AFW pump suction. The testing requirements and Frequency for this SR are in accordance with the Inservice Testing Program.

REFERENCES

1. FSAR, Chapter 10.
2. Design Basis Document IP3-DBD-303, "Auxiliary Feedwater System".
3. Design Basis Document IP3-DBD-319, "Condensate and Condensate Polishing Systems".
4. IP3-CALC-MW-03548.

B 3.7 PLANT SYSTEMS

B 3.7.8 Component Cooling Water (CCW) System

BASES

BACKGROUND

The Component Cooling Water (CCW) System is a closed-loop cooling system that provides cooling water for systems and components important to safety that are located in the Primary Auxiliary Building, the Fuel Storage Building, and the Containment Building. The CCW System transfers its heat load to the Service Water System via CCW heat exchangers. The Service Water System is a once through cooling system that transfers its heat load to the ultimate heat sink, the Hudson River.

The CCW System provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, the CCW System also provides this function for various nonessential components including the spent fuel storage pool. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Service Water System, and thus to the environment.

The CCW System consists of three pumps and two heat exchangers. These components are divided into two independent, full capacity cooling loops with each loop consisting of one pump and a heat exchanger. The third CCW pump can be aligned to replace the pump in either loop. Each of the three CCW pumps is powered from a separate safeguards power train.

The CCW loops are cross connected during normal and emergency operation; however, the cooling loads are divided between the two loops so that each loop is capable of supplying the necessary service to support continued containment sump and core recirculation following a LOCA while supplying normal loads. Operating CCW loops cross-connected allows use of either CCW heat exchanger to cool all normal and post accident heat loads. Any service water system pump can be used to support either or both CCW heat exchangers. Isolation valves allow each loop to be isolated and operated as an independent component cooling loop.

(continued)

BACKGROUND (continued)

This configuration facilitates detection of radioactivity entering the loop for leak detection or isolation of a piping or component failure during an event. A surge tank in each loop ensures that sufficient net positive suction head is available.

CCW pumps continue to operate following a safety injection signal without loss of offsite power (LOOP); however, CCW pumps are stripped and must be started as needed following any event that includes a LOOP. Note that the CCW pumps are not re-started during the injection phase; therefore, the water volume of the CCW system must act as a heat sink during the injection phase when the CCW pumps are not running. This is acceptable even though safety injection pump bearings are cooled by CCW because the cooling water is circulated by a booster pump directly connected to the injection pump motor shaft. During the injection phase of the accident, the Auxiliary Component Cooling Water Pumps operate and provide flow to the Recirculation Pump motor coolers. However, credit for motor cooling is only required in the recirculation phase. The Auxiliary Component Cooling Water Pumps are not governed by this LCO.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the FSAR, Section 9.3 (Ref. 1). The principal safety related function of the CCW System is the removal of decay heat from the reactor via the Residual Heat Removal (RHR) System. This may be during a normal or post accident cooldown and shutdown.

APPLICABLE SAFETY ANALYSES

The design basis of the CCW System is for one CCW loop to remove the post loss of coolant accident (LOCA) heat load from the containment sump during the recirculation phase. Any one of the three CCW pumps in conjunction with any one of the two CCW heat exchangers is sufficient to accommodate the normal and post accident heat load if the CCW system is operated as two cross connected loops. Either CCW pump in conjunction with either CCW heat exchanger or the third CCW pump in conjunction with either associated CCW heat exchanger is sufficient if the CCW loops are isolated.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The CCW System also functions to cool the unit from RHR entry conditions ($T<350^{o}F$) to Mode 5 ($T<200^{o}F$), during normal and post accident operations. The time required to cool from $350^{o}F$ to $200^{o}F$ is a function of the number of CCW, SWS and RHR trains operating. As presented in UFSAR, Section 9, two trains of pumps and heat exchangers are usually used to remove residual and sensible heat during normal plant cool-down. If one train of pumps and/or heat exchangers is not operable, safety operation is governed by Technical Specifications and safe shutdown of the plant is not affected; however, the time for cool-down is extended. One CCW train is sufficient to remove decay heat during subsequent operations with $T<200^{o}F$. The above conditions assume a maximum service water temperature of $95^{o}F$ occurring simultaneously with the maximum heat loads on the system.

Because the component cooling pumps do not run during the injection phase if the event is accompanied by a loss of offsite power, the water volume of the CCW system is used as a heat sink. This heat load causes a temperature rise of approximately 7 ^{0}F per hour in the component cooling water with no credit taken for the water volume in the surge tank. With a minimum initial CCW temperature of 110 ^{0}F at the start of the accident, 6 hours are available before the cooling water temperature reaches 150 ^{0}F; 10 hours is available before reaching 180 ^{0}F. Evaluations of the heat removal capability of the CCW system are contained in References 2, 3 and 5.

The CCW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power.

The CCW System satisfies Criterion 3 of 10 CFR 50.36.

LCO

The CCW loops are independent of each other to the degree that each has separate controls and power supplies and the operation of one does not depend on the other. In the event of a DBA, one CCW loop is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two loops of CCW must be OPERABLE. At least one CCW loop will operate during the recirculation phase assuming the worst case single active failure occurs coincident with a loss of offsite power.

(continued)

LCO (continued)

A CCW loop consists of any of the three CCW pumps in conjunction with a CCW heat exchanger.

A CCW loop is considered OPERABLE when:

a. The pump and associated surge tank are OPERABLE; and

b. The associated piping, valves, heat exchanger, and instrumentation and controls required to perform the safety related function are OPERABLE.

The isolation of CCW from components or systems may render those components or systems inoperable but does not affect the OPERABILITY of the CCW System.

Note that the auxiliary component cooling water pumps support the Containment Recirculation pumps only and are governed by LCO 3.5.2, ECCS - Operating.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCW System is a normally operating system, which must be prepared to perform its post accident safety functions, primarily RCS heat removal, which is achieved by cooling the RHR heat exchanger.

In MODE 5 or 6, the OPERABILITY requirements of the CCW System are determined by the systems it supports.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops — MODE 4," be entered if an inoperable CCW loop results in an inoperable RHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

If one CCW loop is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the

(continued)

ACTIONS

A.1 (continued)

remaining OPERABLE CCW loop is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE loop, and the low probability of a DBA occurring during this period.

B.1 and B.2

If the CCW loop cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR is modified by a Note indicating that the isolation of the CCW flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CCW System.

Verifying the correct alignment for manual, power operated, and automatic valves in the CCW flow path provides assurance that the proper flow paths exist for CCW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. Valves located inside containment are considered to be locked. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. Valves that are throttled are verified by verification of required flow.

The 92 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.8.2

This SR verifies proper automatic operation of the CCW valves on an actual or simulated actuation signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit 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 Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.8.3

This SR verifies proper automatic operation of the CCW pumps on an actual or simulated actuation signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.8.3 (continued)

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit 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 Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 9.3.

2. FSAR, Section 6.2.

3. WCAP-12313, "Safety Evaluation for an Ultimate Heat Sink Temperature Increased to 95 ^{0}F at IP-3."

4. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

5. EC 40623, “Re-Analysis of IP3 Component Cooling Water (CCW) System with New / Expanded Performance Ranges for System Pumps”

B 3.7 PLANT SYSTEMS

B 3.7.9 Service Water System (SWS)

BASES

BACKGROUND

The SWS provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the SWS also provides this function for various safety related and non-safety related components. The safety related function is covered by this LCO.

The SWS consists of two separate, 100% capacity, safety related, cooling water headers. Each header is supplied by three pumps and includes the piping up to and including the isolation valves on individual components cooled by the SW. Each of the 6 SWS pumps is equipped with rotary strainers and isolation valves.

SWS heat loads are designated as either essential or nonessential. The essential SWS heat loads are those which must be supplied with cooling water immediately in the event of a LOCA and/or loss of offsite power (LOOP). Examples of essential loads are the emergency diesel generators (EDGs), containment fan cooler units (FCUs) and control room air conditioning system (CRACS). The nonessential SWS heat loads are those which are required only following the switch over to the recirculation phase following a postulated LOCA. Examples of nonessential loads are the component cooling water (CCW) heat exchangers.

The FCUs are connected in parallel to the essential SWS header. Normal SWS flow to the FCUs is controlled by TCV-1103. Required ESFAS flow to all five FCUs is initiated when either of the redundant SWS to FCU ESFAS valves (TCV-1104 or TCV-1105) opens automatically in response to an ESFAS actuation signal.

The EDGs are connected in parallel to the essential SWS header. Required ESFAS flow to all three EDGs is initiated when either of the redundant SWS to EDG ESFAS valves (FCV-1176 or FCV-1176A) opens automatically in response to an ESFAS actuation which starts the EDGs.

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BACKGROUND (continued)

The CRACS are connected in parallel to the essential SWS header. Required ESFAS flow to both CRACS is provided continuously because the redundant SWS to CRACS valves (TCV-1310/1311 and TCV-1312/1313) have been modified to provide the required flow at all times.

Either of the two SWS headers can be aligned to supply the essential heat loads or the nonessential SWS heat loads. Both the essential and nonessential SWS HEADERS are operated to support normal plant operation and the plant response to accidents and transients. The SWS PUMPS associated with the SWS header designated as the essential header will start automatically. The SWS pumps associated with the SWS header designated as the nonessential header must be manually started when required following a LOCA.

The essential SWS heat loads can be cooled by any two of the three service water pumps on the essential header. The nonessential SWS heat loads can be cooled by any one of the three service water pumps on the nonessential header. To ensure adequate flow to the essential header, the essential and nonessential headers may be cross connected only as necessary while swapping the essential SWS header with the non essential SWS header.

Service water pump suctions are located below the mean sea level in the Hudson River, the ultimate heat sink. This configuration ensures adequate submergence of the SWS pump suctions.

Additional information about the design and operation of the SW, along with a list of the components served, is presented in the FSAR, Section 9.6, (Ref. 1). The principal safety related function of the SWS is the removal of decay heat from the reactor via the CCW System.

APPLICABLE SAFETY ANALYSES

The design basis of the SWS is as follows: post accident essential SWS heat loads can be cooled by any two of the three service water pumps on the designated essential header; and, post accident nonessential SWS heat loads can be cooled by any one of the three service water pumps on the designated nonessential header. With the minimum number of pumps operating, the essential and nonessential

(continued)

APPLICABLE SAFETY ANALYSES (continued)

headers of the SWS have the required capacity to remove core decay heat following a design basis LOCA as discussed in References 1, 2 and 3. This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System by the ECCS pumps. The Service Water System was designed to fulfill required safety functions while sustaining: (a) the single failure of any active component used during the injection phase of a postulated LOCA with or without a LOOP, or (b) the single failure of any active or passive component used during the long-term recirculation phase with or without a LOOP.

The operating modes of the IP3 SWS are as follows: a) normal mode; b) post-LOCA injection mode; and, c) post-LOCA recirculation mode. The postulated failure conditions of the SWS must include consideration of the limiting case for each operating mode of the system which are as follows:

a. Loss of the 10 inch turbine building service water supply header during normal operation and a seismic event;
b. Loss of instrument air, during the post-LOCA injection phase concurrent with single active component failure.
c. Loss of a SWS pump on both the essential and nonessential headers (resulting from an EDG failure) during the post-LOCA recirculation phase.

The SW, in conjunction with the CCW System, also cools the unit from residual heat removal (RHR) entry conditions to MODE 5 during normal and post accident operations. The time required for this evolution is a function of CCW and RHR system flow, SWS flow and UHS temperature. The design assumes a maximum SWS temperature of 95^0F occurring simultaneously with maximum heat loads on the system (Ref. 3). As presented in UFSAR, Section 9, two trains of pumps and heat exchangers are usually used to remove residual and sensible heat during normal plant cool-down. If one train of pumps and/or heat exchangers is not operable, safe operation is governed by Technical Specifications and safe shutdown of the plant is not affected; however, the time for cool-down is extended.

The SWS satisfies Criterion 3 of 10 CFR 50.36.

(continued)

LCO

Three of the three SWS pumps associated with the SWS header designated as the essential header; and, two of the three SWS pumps associated with the SWS header designated as the nonessential header must be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, while sustaining: (a) the single failure of any active component used during the injection phase of a postulated LOCA with or without a LOOP, or (b) the single failure of any active or passive component used during the long-term recirculation phase with or without a LOOP.

An SWS header is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. The required number of pumps, consistent with the header's designation as the essential or nonessential header, are OPERABLE; and

b. The essential and nonessential headers are isolated from each other by at least one closed valve except as specified by the NOTE to the ACTIONS;

c. The associated piping, valves, instrumentation and controls required to perform the safety related function are OPERABLE.

The SWS to FCU valves (TCV-1104 or TCV-1105) and SWS to EDG valves (FCV-1176 or FCV-1176A) are OPERABLE when they open automatically in response to ESFAS actuation signal or are blocked open.

Service water valves SWN-35-1 and SWN-35-2, at the CCWHX 31 and 32 outlets, are required to be opened no more than 27.5 and 27 degrees open, respectively, for single pump runout protection during the re-establishment of non-essential service water for long term recirculation and non-SI Blackout for MODES 1 to 4. The exception to this is during plant cooldown from 350^0F to Cold Shutdown (MODE 5) where these valves may be opened without restriction provided that:

- Two non-essential service water pumps are operating,
- the non-essential SW header low pressure alarm is maintained clear, and
- the valves are restored to their 27.5 / 27 degrees open positions should a reduction to single non-essential pump operation result.

(continued)

BASES

LCO (continued)

The latter is achieved by the implementation of administrative controls to ensure that a dedicated Operator with direct communication from the Control Room takes manual action to restore the valves to their prescribed position limits well within 2 hours. These administrative controls also include procedural guidance and restrictions, such as not allowing this configuration with the headers being swapped or cross-tied.

APPLICABILITY

In MODES 1, 2, 3, and 4, the SWS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the SWS and required to be OPERABLE in these MODES. In MODES 5 and 6, the OPERABILITY requirements of the SWS are determined by the systems it supports.

ACTIONS

The ACTIONS are modified by a Note that specifies that LCO 3.0.3 is not applicable for 8 hours while swapping the essential SWS header with the nonessential SWS header but only if LCO 3.7.9 will be met after the essential and non-essential header are swapped. This means that the essential and nonessential SWS headers may be cross-connected for up to 8 hours during transfer of the designated essential SWS header to the alternate SWS header. This is acceptable because of the low probability of an event while the headers are cross connected.

A.1 and B.1

If one of the three required SWS pumps on the essential SWS header is inoperable (i.e., Condition A), three Operable pumps must be restored to the essential SWS header within 72 hours. Likewise, if one of the two required SWS pumps on nonessential SWS header is inoperable (i.e., Condition B), the header must be restored so that there are two Operable pumps for the nonessential SWS header within 72 hours. With one required SWS pump inoperable on either or both SWS headers, the remaining OPERABLE SWS pumps are adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in an OPERABLE SWS pump could result in loss of SWS function. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE pump(s) in the same header, and the low probability of a DBA occurring during this time period.

(continued)

ACTIONS (continued)

C.1 and D.1

Required ESFAS flow to all three EDGs is initiated when either of the redundant SWS to EDG valves (FCV-1176 or FCV-1176A) opens automatically in response to an ESFAS actuation which starts the EDGs. Similarly, required ESFAS flow to all five FCUs is initiated when either of the redundant SWS to FCU valves (TCV-1104 or TCV-1105) opens automatically in response to an ESFAS actuation signal. The SWS to FCU valves and SWS to EDG valves are OPERABLE when they open automatically in response to an ESFAS actuation signal or are blocked open.

If one of the redundant SWS to EDG valves is inoperable, a single failure of the redundant valve could result in the failure of all three EDGs shortly after the initiation of an event. If one of the redundant SWS to FCU valves is inoperable, a single failure of the redundant valve could result in the failure of all five FCUs. Therefore, a Completion Time of 12 hours is established to restore the required redundancy.

A 12 hour Completion Time is acceptable for the SWS to EDG valves because SWS to the EDGs is still available and the low probability of an event with a loss of offsite power during this period. A 12 hour Completion Time is acceptable for the SWS to FCU valves because SWS to the FCUs is still available, the availability of Containment Spray, and the low probability of an event during this period.

If both SWS to EDG valves or both SWS to FCU valves are inoperable, entry into LCO 3.0.3 is required.

E.1

If the SWS piping and valves are inoperable for reasons other than those listed in Conditions A, B, C or D, the SWS must be restored within 12 hours. This is necessary to ensure that repairs to affected portions of the SWS are completed in a timely manner. This Action also ensures no unnecessary transients (i.e. plant shutdown) are placed on the plant as a result of conditions in the SWS that may challenge OPERABILITY but do not result in a loss of function.

A 12 hour Completion Time is acceptable for SWS piping and valves other than those listed in Conditions A, B, C, or D based on the low probability of an event during this period. Additionally, the 12 hour Completion Time allows the Operator to perform the evaluations and/or actions necessary for restoring the SWS OPERABILITY. This Action is in lieu of the potential for decreased safety as a result of diverting the Operator's attention to the actions associated with taking the unit to shutdown.

(continued)

ACTIONS

F.1 and F.2

If more than one required SWS pump in either the essential or the nonessential header is inoperable; or, if the flow path associated with either header is not capable of performing its safety function (e.g., both SWS to EDG valves or both SWS to FCU valves are inoperable), then the unit must be placed in a MODE in which the LCO does not apply.

Additionally, if an SWS header cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced.

To achieve the required status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action F.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

This SR is modified by a Note indicating that the isolation of the SWS components or systems may render those components inoperable, but does not affect the OPERABILITY of the SW.

Verifying the correct alignment for manual, power operated, and automatic valves in the SWS flow path provides assurance that the proper flow paths exist for SWS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. 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.

For SWN-35-1 and SWN-35-2, see Bases LCO section for valve position requirements below 350^0F.

The 92 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.9.2

This SR verifies proper automatic operation of the SWS valves on an actual or simulated actuation signal. The SWS is a normally operating system that cannot be fully actuated as part of normal testing. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit 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 Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.3

This SR verifies proper automatic operation of the SWS pumps on an actual or simulated actuation signal. The SWS is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit 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 Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 9.6.
2. FSAR, Section 6.2.
3. WCAP – 16212P, Indian Point Nuclear Power Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report, June 2004.
4. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.10 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The UHS provides a heat sink for processing and operating heat from safety related components during a transient or accident, as well as during normal operation. This is done by utilizing the Service Water System (SWS) and the Component Cooling Water (CCW) System.

The ultimate heat sink for IP3 is the Hudson River. The UHS and supporting structures are capable of providing sufficient cooling for thirty days and are sufficient to:

a) Support simultaneous safe shutdown and cooldown of both operating nuclear units at the Indian Point site and maintain them in a safe condition, and

b) In the event of an accident in one unit, support required response to that accident and permit simultaneous safe shutdown and cooldown of the remaining unit and maintain them in a safe shutdown condition.

In the event of an accident in one unit, support required response to that accident and permit simultaneous safe shutdown and cooldown of the remaining unit and maintain them in a safe shutdown condition.

The ultimate heat sink is capable of withstanding the effects of the most severe natural phenomena associated with the Indian Point site, other site related events and a single failure of man-made structural features.

The two principal functions of the UHS are the dissipation of residual heat after reactor shutdown, and dissipation of residual heat after an accident.

APPLICABLE SAFETY ANALYSES

The UHS is the sink for heat removed from the reactor core following all accidents and anticipated operational occurrences in which the unit is cooled down and placed on residual heat removal (RHR) operation. Because IP3 uses the UHS as the normal heat sink for condenser cooling via the Circulating Water System, unit operation at full power is its maximum heat load. Its maximum post accident heat load occurs shortly after a design basis loss of coolant accident (LOCA). Near this time, the unit switches from injection to recirculation and the containment cooling systems and containment recirculation system are required to remove the core decay heat.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The operating limits are based on conservative heat transfer analyses for the worst case LOCA. Reference 1 provides the details of the assumptions used in the analysis, which include worst expected meteorological conditions, conservative uncertainties when calculating decay heat, and worst case single active failure (e.g., single failure of a manmade structure). The UHS meets Regulatory Guide 1.27 (Ref.3), which requires a 30 day supply of cooling water in the UHS.

The UHS satisfies Criterion 3 of 10 CFR 50.36.

LCO

The UHS is required to be OPERABLE and is considered OPERABLE if it contains water at or below the maximum temperature that would allow the SWS to operate for at least 30 days following the design basis LOCA without the loss of net positive suction head (NPSH), and without exceeding the maximum design temperature of the equipment served by the SWS. To meet this condition, the UHS temperature must not exceed 95^0F.

APPLICABILITY

In MODES 1, 2, 3, and 4, the UHS is required to support the OPERABILITY of the equipment serviced by the UHS and required to be OPERABLE in these MODES.

In MODE 5 or 6, the OPERABILITY requirements of the UHS are determined by the systems it supports.

ACTIONS

A.1 and A.2

If UHS temperature > 95^0F, or is inoperable for reasons other than high temperature, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 7 hours and in MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 5). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 5, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

ACTIONS (continued)

A.1 and A.2

Required Action A.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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 3.7.10.1

This SR verifies that the SWS is available to cool the CCW System to at least its maximum design temperature with the maximum accident or normal design heat loads for 30 days following a Design Basis Accident. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES. This SR verifies that the average water temperature of the UHS is ≤ 95^0F. Requirements for UHS monitoring instrumentation are governed by the Technical Requirements Manual (Ref. 4).

REFERENCES

1. FSAR, Section 9.6.
2. WCAP – 16212P, Indian Point Nuclear Power Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report, June 2004.
3. Regulatory Guide 1.27.
4. IP3 Technical Requirements Manual.
5. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Ventilation System (CRVS)

BASES

BACKGROUND

The CRVS provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The Control Room Ventilation System consists of the following equipment: a single filter unit consisting of two roughing filters, two high efficiency particulate air (HEPA) filters; two activated charcoal adsorbers for removal of gaseous activity (principally iodines); two 100% capacity filter booster fans; and, a single duct system including dampers, controls and associated accessories to provide for three different air flow configurations. The air-conditioning units associated with the CRVS are governed by LCO 3.7.12, “Control Room Air Conditioning System (CRACS).”

The CRVS is divided into two trains with each train consisting of a filter booster fan with its associated inlet damper, an air conditioning unit fan powered from the same safeguards power train with its associated inlet damper, and the following components which are common to both trains: the control room filter unit, Damper A (filter unit bypass for outside air makeup to the Control Room Envelope (CRE)), Damper B (filter unit inlet for outside air makeup to the CRE, and the toilet and locker room exhaust fan. The two filter booster fans (F 31 and F 32) are powered from safeguards power trains 5A (EDG 33) and 6A (EDG 32), respectively. The automatic dampers that are common to both trains are positioned in the fail-safe position (open or closed) by either of the redundant actuation channels.

The control room envelope (CRE) is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and may encompass other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Habitability Program.

(continued)

BASES

BACKGROUND (continued)

The CRVS is an emergency system, parts of which operate during normal unit operations.

The three different CRVS air flow configurations are as follows:

a) CRVS Mode 2 Normal operation – Ventilation is provided to the CRE via outside air drawn through Damper A driven by the operation of the CRACS fan(s) and the toilet/locker room exhaust fan;

b) CRVS Mode 3 Incident mode with outside air makeup (known as the 10% incident mode) – Ventilation and pressurization are provided for the CRE via altered outside air drawn through Damper B, driven by the operation of the CRACS fan(s) and its associated filter booster fan;

c) CRVS Mode 4 Incident mode with no outside air makeup (i.e. 100% recirculation mode) - In this mode there is no ventilation provided to the CRE. Both A and B Dampers are closed and the only associated CRVS components operating are the CRACS fan(s).

CRVS Mode 3 (10% Incident Mode) is the required method of operation during any radiological event because it provides outside air for pressurization of the CRE. It has been demonstrated via industry experience with tracer gas testing that increased pressurization helps attenuate unfiltered inleakage.

On a Safety Injection signal or high radiation in the CRE (Radiation Monitor R-1), the CRVS will actuate to the CRVS Mode 3 incident mode with outside air makeup (known as the 10% incident mode). This will cause one of the two filters booster fans to start, the locker room

(continued)

BASES

BACKGROUND (continued)

exhaust fan to stop, and CRVS dampers to open or close as necessary to filter all incoming outside air. In the event that the first booster fan fails to start, the second booster fan will start after a predetermined time delay.

A single train, operating at a minimal flow rate of <2000 cfm, will create a slight positive pressure in the CRE relative to external areas adjacent to the CRE boundary. The CRVS operation in maintaining the CRE habitable is discussed in the FSAR, Section 9.9 (Ref. 1).

The CRE is continuously monitored by radiation and toxic gas detectors.

The CRVS does not actuate automatically in response to toxic gases. Separate chlorine, ammonia and oxygen probes are provided to detect the presence of these gases in the outside air intake. Additionally, monitors in the CRE will detect low oxygen levels and high levels of chlorine and ammonia. The CRVS may be placed in the CRVS Mode 4 incident mode with no outside air makeup (i.e. 100% recirculation mode) to respond to these conditions. Instrumentation for toxic gas monitoring is governed by the IP3 Technical Requirements Manual (TRM) (Ref. 4). Generally, the manually initiated actions of the toxic gas isolation state are more restrictive, and will override the actions of the emergency radiation state.

If for any reason it is required or desired to operate with 100% recirculated air (e.g., toxic gas condition is identified), the CRVS can be placed in the CRVS Mode 4 incident mode with no outside air makeup (i.e. 100% recirculation mode) by remote manually operated switches. The Firestat detectors will shutdown both air conditioning units associated with the CRVS, resulting in shutting the outside air dampers. However, if any filter booster fan was running at that time, it will be tripped.

The CRVS is designed in accordance with Seismic Category I requirements.

The CRVS is designed to maintain the CRE for 30 days of continuous occupancy after a Design Basis Accident (DBA) without exceeding a 5 rem TEDE dose.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The CRVS active components are arranged in redundant, safety related ventilation trains. The location of components and ducting within the CRE provides protection from natural phenomena events. The CRVS provides airborne radiological protection for the CRE occupants, as demonstrated by the control room accident dose analyses for the most limiting design basis accident (i.e., DBA LOCA) fission product release (Ref. 3).

Radiation monitor R-1 is not required for the Operability of the Control Room Ventilation System because control room isolation is initiated by the safety injection signal in MODES 1, 2, 3, 4, and CRE isolation is not credited for maintaining radiation exposure within General Design Criteria 19 limits following a fuel handling accident or gas-decay-tank rupture.

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

The worst case active failure of a component of the CRVS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. However, the original CRVS design was not required to meet single failure criteria and, although upgraded from the original design, CRVS does not satisfy all requirements in IEEE-279 for single failure tolerance.

Each of the automatic dampers that are common to both trains is positioned in the CRVS Mode 3 (10% incident mode) fail-safe position (open or closed) by either of the redundant actuation channels.

The CRVS satisfies Criterion 3 of 10 CFR 50.36.

LCO

Two CRVS trains are required to be OPERABLE to ensure that at least one is available. Total system failure, such as from a loss of both ventilation trains or from an inoperable CRE boundary, could result in exceeding a dose of 5 rem TEDE to the CRE occupants in the event of a large radioactive release.

(continued)

LCO (continued)

Each CRVS train is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE in both trains. A CRVS train is OPERABLE when the associated:

a. Filter booster fan and an air-conditioning unit fan powered from the same safeguards power train are OPERABLE;

b. HEPA filters and charcoal absorbers are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Valves, and dampers are OPERABLE or in the incident mode, and air circulation can be maintained.

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

Criteria has been established for leakage from primary coolant sources outside of containment which could render the CCR Filter System inoperable. For more information refer to Technical Specification 5.5.2, “Primary Coolant Sources Outside of Containment” and Engineering Report No. IP-RPT-08-00001, “Primary Coolant Sources Outside of Containment”.

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

Instrumentation for toxic gas monitoring is governed by the IP3 Technical Requirements Manual (TRM) (Ref. 4) and is not included in the LCO.

FSAR Section 14.2.1 (Reference 2) says “No movement of irradiated fuel in the reactor is made until the reactor has been subcritical for at least 84 hours.”

(continued)

BASES

APPLICABILITY

In MODES 1, 2, 3 and 4, CRVS must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA.

During movement of recently irradiated fuel assemblies, the CRVS must be OPERABLE to cope with the release from a fuel handling accident involving recently irradiated fuel. The CRVS is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 84 hours), due to radioactive decay.

Administrative controls address the role of the CRVS in maintaining control room habitability following an event at Indian Point Unit 2.

ACTIONS

A.1

When one CRVS train is inoperable, for reasons other than an inoperable CRE boundary, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CRVS train is adequate to perform the CRE occupants protection function. However, the overall reliability is reduced because a failure in the OPERABLE CRVS train could result in loss of CRVS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

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

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

During the period that the CRE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological

(continued)

BASES

ACTIONS (continued)

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

C.1

When neither CRVS train is Operable, for reasons other than Condition B, action must be taken to restore at least one train to OPERABLE status within 72 hours. The 72 hour Completion Time is acceptable because of the low probability of a DBA occurring during this time period.

D.1 and D.2

If Required Actions of Conditions A, B or C are not met within the required Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 8). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 8, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

ACTIONS (continued)

Required Action D.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

E.1 and E.2

Reference 3 did not address exposure to CRE resulting from fuel handling accidents when less than 84 hours of decay time have elapsed if the CRE ventilation safety function is not met.

Therefore, when only one CRVS train is OPERABLE during movement of recently irradiated fuel, action must be taken to immediately place the OPERABLE CRVS train in the pressurization mode. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected. An alternative to Required Action E.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

F.1

Reference 3 did not address exposure to CRE occupants resulting from fuel handling accidents when less than 84 hours of decay time have elapsed if the CRE ventilation safety function is not met. Therefore, during movement of recently irradiated fuel when neither CRVS train is OPERABLE or with one or more CRVS trains inoperable due to an inoperable CRE boundary, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not too severe, testing each train once every month provides an adequate check of this system. Note that a CRVS train includes both the filter booster fan and an air-conditioning unit fan powered from the same safeguards power train. The 31 day Frequency is based on the reliability of the equipment and the two train redundancy.

SR 3.7.11.2

This SR verifies that the required CRVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CRVS filter tests are in accordance with the sections of Regulatory Guide 1.52 (Ref. 3) identified in the VFTP. The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.11.3

This SR verifies that each CRVS train starts and operates on an actual or simulated actuation signal. The Frequency of 24 months is based on operating experience which has demonstrated this Frequency provides a high degree of assurance that the booster fans will operate and dampers actuate to the correct position when required and is consistent with the typical refueling cycle.

SR 3.7.11.4

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

The CRE is considered habitable when the radiological dose to CRE Occupants calculated in the licensing basis analysis of DBA consequences is no more than 5 rem TEDE and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.11.4 (continued)

Required Action B.3 allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 5) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 6).

These compensatory measures may also be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 7). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

REFERENCES

1. FSAR, Section 9.9.
2. FSAR, Chapter 14.
3. Safety Evaluation Report (SER) for IP3 Amendment 224.
4. IP3 Technical Requirements Manual.
5. Regulatory Guide 1.196.
6. NEI 99-03, “Control Room Habitability Assessment,” June 2001.
7. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, “NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability.” (ADAMS Accession No. ML040300694).
8. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.12 Control Room Air Conditioning System (CRACS)

BASES

BACKGROUND

The CRACS provides temperature control for the control room following isolation of the control room.

The CRACS consists of two trains that provide cooling of recirculated control room air. Each train consists of, cooling coils, instrumentation, and controls to provide for control room temperature control. The CRACS (CRACS 31 and CRACS 32) are powered from safeguards power trains 5A (EDG 33) and 6A (EDG 32), respectively. The CRACS units are supplied with cooling water from the essential service water header and each unit is capable of performing its design function during an accident with a service water inlet temperature ≤ 95°F.

The CRACS is an emergency system, parts of which may also operate during normal unit operations. Each CRACS unit is sized to provide 60% of the cooling capacity required during normal operation and 100% of the cooling capacity required during an accident. The CRACS operation in maintaining the control room temperature is discussed in the FSAR, Section 9.9 (Ref. 1).

During normal operation, five supplemental air-conditioning units in the Control Room are available to supplement the cooling capacity of the CRACS. These units also provide Control Room heating. These five supplemental air-conditioning units are not assumed to be available during a blackout or design basis accident and, therefore, are not governed by Technical Specifications.

APPLICABLE SAFETY ANALYSES

The design basis of the CRACS is to maintain the control room temperature for 30 days of continuous occupancy. The CRACS is designed so that the functional capacity of the Control Room is maintained at all times, including a Design Basis Accident. Functional capacity of the Control Room means that the ambient temperature for safety equipment located in this room will not exceed 108.2°F. Control Room safety equipment is specified to a temperature of 120°F and the 108.2°F limit for Control room temperature is sufficient to account for the temperature rise in the enclosed cabinets. Functional capacity of the Control Room can be maintained by one train of CRACS being cooled by the essential service water system assuming the ultimate heat sink temperature is ≤ 95°F.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

Analysis indicates that under worst case conditions, the Control Room temperature could rise to approximately 106ºF following the loss of one CRACS train assuming all lights, except emergency lights, are turned off (Ref.1). Detectors and controls are provided for control room temperature control. The CRACS is designed in accordance with Seismic Category I requirements. The CRACS is capable of removing sensible and latent heat loads from the control room, which include consideration of equipment heat loads and personnel occupancy requirements, to ensure equipment OPERABILITY.

A failure of a component of the CRACS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. However, the original CRACS design was not required to meet single failure criteria and, although upgraded from the original design, CRACS does not satisfy all requirements in IEEE-279 for single failure tolerance.

The CRACS satisfies Criterion 3 of 10 CFR 50.36.

LCO

Two trains of the CRACS are required to be OPERABLE to ensure that at least one is available, assuming a single failure disabling the other train. Total system failure could result in the equipment operating temperature exceeding limits in the event of an accident.

The CRACS is considered to be OPERABLE when the individual components necessary to maintain the control room temperature are OPERABLE in both trains. These components include the cooling coils and common temperature control instrumentation. In addition, the CRACS must be operable to the extent that air circulation can be maintained.

(continued)

APPLICABILITY

In MODES 1, 2, 3 and 4, the CRACS must be OPERABLE to ensure that the control room temperature will not exceed equipment operational requirements following isolation of the control room.

The CRACS is not required in MODE 5 or 6, or during movement of irradiated fuel assemblies and core alterations because analysis indicates that isolation of the control room is not required for maintaining radiation exposure within acceptable limits following a fuel handling accident or gas decay tank rupture.

ACTIONS

A.1

With one CRACS train inoperable, action must be taken to restore OPERABLE status within 30 days. In this Condition, the remaining OPERABLE CRACS train is adequate to maintain the control room temperature within limits. However, the overall reliability is reduced because a single failure in the OPERABLE CRACS train could result in loss of CRACS function. The 30 day Completion Time is based on the low probability of an event requiring control room isolation, the consideration that the remaining train can provide the required protection, and that alternate non-safety related cooling means are typically available.

B.1

When neither CRACS train is Operable, action must be taken to restore at least one train to OPERABLE status within 72 hours. The 72 hour Completion Time is acceptable because of the low probability of a DBA occurring during this time period and because alternate non-safety cooling means are typically available.

C.1 and C.2

If Required Actions A.1 or B.1 are not met within the required Completion Time, the unit must be placed in a MODE in which the overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 3). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 3, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

BASES

ACTIONS (continued)

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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 3.7.11.4

This SR verifies that the heat removal capability of the system is sufficient to remove the heat load required to maintain functional capacity of the Control Room at all times (Ref. 1). This SR consists of a combination of testing and calculations. Testing consists of installing pressure gauges on the inlet and outlet sides of the CCR HVAC compressor to obtain refrigerant pressures on a periodic basis to provide input to this SR to demonstrate that the unit is performing within the manufacturer's defined performance limit. The 24 month Frequency is appropriate since significant degradation of the CRACS is slow and is not expected over this time period.

REFERENCES

1. FSAR, Section 9.9.

2. Safety Evaluation Report (SER) for IP3 Amendment 224.

3. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.13 Fuel Storage Building Emergency Ventilation System (FSBEVS)

BASES

BACKGROUND

The FSBEVS filters airborne radioactive particulates from the area of the fuel pool following a fuel handling accident. The FSBEVS, in conjunction with other normally operating systems, also provides environmental control of temperature and humidity in the fuel storage building.

The Fuel Storage Building (FSB) ventilation system maintains environmental conditions in the building enclosing the spent fuel pit and consists of the following:

Two FSB air tempering units, each consisting of: a steam heating coil, a supply fan, and an isolation damper;

One FSB exhaust fan and associated outlet damper;

One FSB exhaust filtration unit consisting of roughing, HEPA, and charcoal filters which includes the pneumatically operated inlet and outlet dampers for the carbon filter and manually operated dampers that allow the carbon filter to be bypassed;

Inflatable seals on man doors,

Area Radiation Monitor (R-5) consisting of an extended range area monitor used to measure the area radiation fields of the Fuel Storage Building; and,

Ductwork, dampers, and instrumentation needed to support system operation,

<u>During normal operation</u>, the FSB air tempering units and the FSB exhaust fan operate, as necessary, to ventilate and, if necessary, heat the FSB. Only one air tempering unit used to supply outside air to the south end of the FSB and the FSB exhaust fan is used to exhaust

(continued)

BACKGROUND (continued)

air from the north end of the FSB through the roughing filters and HEPA filters and is released to the environment via the plant vent. FSB air flow is directed from radiologically clean to less clean areas to prevent the spread of contamination. Additionally, the FSBEVS is designed so that the exhaust fan capacity is greater than the supply fan(s) capacity so that the FSB is normally maintained at a slight negative pressure. This ensures that ventilation air leaving the FSB passes through the filters and HEPA in the exhaust filtration unit and is released to the environment via the plant vent. When not handing irradiated fuel in the FSB, the carbon filter in the exhaust filtration unit is normally bypassed to extend the life of the charcoal. In this configuration, the manually operated charcoal filter bypass dampers are left open and the automatically operated charcoal filter face dampers (inlet and outlet dampers) are closed.

<u>During irradiated fuel handling activities in the FSB,</u> the FSBEVS is operated as described above except that the manually operated charcoal filter bypass dampers are closed and the charcoal filter face dampers (inlet and outlet dampers) are opened. In this configuration, the FSB is still maintained at a slight negative pressure but all FSB ventilation exhaust is directed through the roughing filters, HEPA filters, and charcoal filters and is released to the environment via the plant vent.

<u>Following an Area Radiation Monitor (R-5) signal or manual actuation to the emergency mode of operation</u>, the ventilation supply fans stop automatically and the associated ventilation supply dampers close automatically. The charcoal filter face dampers (inlet and outlet dampers) open automatically, if not already open. Additionally, the rollup coiling truck bay door closes, if open, and the inflatable seals on the man doors are actuated. The FSB exhaust fan continues to operate. With the FSB ventilation supply stopped and the FSB boundary secured, the FSB exhaust fan is capable of maintaining the FSB at a pressure $\leq$ -0.5 inches water gauge with respect to atmospheric pressure with the exhaust flow rate $\leq$ 20,000 cfm. Ventilation dampers required to establish the boundary or flow path (e.g., air tempering unit ventilation supply inlet dampers) will fail-

(continued)

BASES

BACKGROUND (continued)

safe into the required emergency mode position. Note that the inflatable seals on man doors are not required for maintaining the FSB at these required post accident conditions.

A push button switch adjacent to the 95' elevation door leading to the Fan House allows the Fuel Storage Building Exhaust Fan to be momentarily shut down and air removed from the man door seal to allow the door to be opened for FSB ingress or egress when in the emergency mode of operation. The fan will automatically restart and the door is resealed after a preset time has elapsed (approximately 30 seconds).

The FSBEVS is discussed in the FSAR, Sections 9.5, and 14.2 (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The FSBEVS design basis is established by the consequences of the limiting Design Basis Accident (DBA), which is a fuel handling accident involving handling recently irradiated fuel. The analysis for a fuel handling accident assumes that the FSB exhaust fan can maintain the FSB at a slight negative pressure (i.e., $\leq$ -0.125 inches water gauge) with respect to atmospheric pressure with the exhaust flow rate $\leq$ 20,000 cfm. Under these conditions, all FSB ventilation exhaust is assumed to be directed through the roughing filters, HEPA filters, and charcoal filters and is released to the environment via the plant vent. This ensures that offsite post accident dose rates are within required limits. Due to radioactive decay, FSBEVS is only required to isolate during fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 84 hours). This analysis is described in Reference 2.

The FSBEVS satisfies Criterion 3 of 10 CFR 50.36.

(continued)

BASES

LCO

This LCO requires that the Fuel Storage Building Emergency Ventilation System is OPERABLE and the FSB boundary is intact. This ensures that the required negative pressure is maintained in the FSB and FSB ventilation exhaust is directed through the roughing filters, HEPA filters, and charcoal filters and is released to the environment via the plant vent. Failure of the FSBEVS or the FSB boundary could result in the atmospheric release from the fuel storage building exceeding the 10 CFR 50.67 (Ref. 3) limits in the event of a fuel handling accident involving handling recently irradiated fuel.

The FSBEVS is considered OPERABLE when the individual components necessary to control exposure in the fuel storage building are OPERABLE. FSBEVS is considered OPERABLE when its associated:

a. Exhaust fan is OPERABLE;

b. Roughing filter, HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration function;

c. Ductwork and dampers are OPERABLE as needed to ensure air circulation can be maintained through the filter;

d. Ventilation supply fan trip function and ventilation supply isolation dampers closure function are OPERABLE or secured in incident position; and

e. FSBEVS charcoal filter bypass dampers are closed and leak tested.

The inflatable seals on man doors are not required for maintaining the FSB at these required post accident conditions. Additionally, the FSBEVS is not rendered inoperable when the FSBEVS exhaust fan is momentarily shut down and air removed from the door seal to allow the door to be opened for FSB ingress or egress when in the emergency mode of operation.

Requirements for the OPERABILITY of the Area Radiation Monitor (R-5) and associated instrumentation that initiates the FSBEVS are addressed in LCO 3.3.8, “Fuel Storage Building Emergency Ventilation System Actuation Instrumentation.”

(continued)

BASES

LCO (continued)

Requirements for leak testing the FSBEVS charcoal filter bypass dampers following closure are governed by the IP3 FSAR.

APPLICABILITY

During movement of recently irradiated fuel in the fuel storage building, the FSBEVS is required to be OPERABLE to mitigate the consequences of the limiting fuel handling accident.

ACTIONS

A.1

When the FSBEVS is inoperable during movement of recently irradiated fuel assemblies in the fuel storage building, action must be taken to place the unit in a condition in which the LCO does not apply. Action must be taken immediately to suspend movement of recently irradiated fuel assemblies in the fuel storage building. This does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

This SR requires periodic verification that the FSBEVS charcoal filter bypass dampers are installed and leak tested. This SR is performed by a visual verification that the bypass dampers are installed and an administrative verification that required leak testing was performed following the last installation of the dampers. Requirements for leak testing the FSBEVS charcoal filter bypass dampers following closure are governed by the IP3 FSAR.

This SR is performed prior to movement of recently irradiated fuel assemblies in the fuel storage building, and once per 92 days thereafter. The 92 day Frequency is appropriate because the bypass dampers are operated under administrative controls which provide a high degree of assurance that the dampers will remain in the required position. This Frequency has been shown to be acceptable through operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.13.2

Standby systems should be checked periodically to ensure that they function properly. As the environmental and normal operating conditions on this system are not severe, testing the FSBEVS once every 31 days provides an adequate check on this system. Systems are operated for $\geq$ 15 minutes to demonstrate the function of the system. The 31 day Frequency is based on the known reliability of the equipment.

SR 3.7.13.3

This SR verifies that the required FSBEVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The FSBEVS filter tests are in accordance with the applicable portions of Regulatory Guide 1.52 (Ref. 4) as specified in the VFTP. The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.13.4

This SR verifies that the FSBEVS starts and operates on an actual or simulated actuation signal. The 92 day Frequency ensures that the SR is performed within a short time prior to a potential need for the FSBEVS and allows the SR to be performed only once prior to or during a refueling outage. This SR Frequency is based on the demonstrated reliability of the system.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.13.5

This SR verifies the integrity of the fuel storage building enclosure. The ability of the fuel building to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the FSBEVS. During the normal mode of operation, the FSBEVS is designed to maintain a slight negative pressure in the fuel storage building, to prevent unfiltered LEAKAGE. This test verifies that the FSB exhaust fan can maintain the FSB at a slight negative pressure (i.e., $\leq$ -0.125 inches water gauge) with respect to atmospheric pressure with the exhaust flow rate $\leq$ 20,000 cfm during a fuel handling accident. The Frequency of 24 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref. 5).

REFERENCES

1. FSAR, Section 9.5.
2. FSAR, Section 14.2.
3. 10 CFR 50.67.
4. Regulatory Guide 1.52 (Rev. 2).
5. NUREG-0800, Section 6.5.1, Rev. 2, July 1981.

B 3.7 PLANT SYSTEMS

B 3.7.14 Spent Fuel Pit Water Level

BASES

BACKGROUND

The minimum water level in the spent fuel pit meets the assumptions of iodine decontamination factors following a fuel handling accident. The specified water level shields and minimizes the general area dose when the storage racks are filled to their maximum capacity. The water also provides shielding during the movement of spent fuel.

A general description of the spent fuel pit design and the Spent Fuel Cooling and Cleanup System is given in the FSAR, Section 9.5 (Ref. 1). The assumptions of the fuel handling accident are given in the FSAR, Section 14.2 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The minimum water level in the spent fuel pit meets the assumptions of the fuel handling accident described in FSAR, Section 14.2 (Ref. 2). The resultant 2 hour thyroid dose per person at the exclusion area boundary satisfies the 10 CFR 50.67 (Ref. 3) limits.

According to Reference 2, there is 23 ft of water between the top of the damaged fuel bundle and the fuel pool surface during a fuel handling accident. With 23 ft of water, the assumptions of Reference 4 can be used directly. In practice, this LCO preserves this assumption for the bulk of the fuel in the storage racks.

The Spent Fuel Pit water level satisfies Criteria 2 and 3 of 10 CFR 50.36.

LCO

The spent fuel pit water level is required to be 23 ft over the top of irradiated fuel assemblies seated in the storage racks. The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 2). As such, it is the minimum required for fuel storage and movement within the spent fuel pit.

(continued)

BASES

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the spent fuel pit, since the potential for a release of fission products exists.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the spent fuel pit water level is lower than the required level, the movement of irradiated fuel assemblies in the spent fuel pit is immediately suspended to a safe position. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position.

If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

This SR verifies sufficient spent fuel pit water is available in the event of a fuel handling accident. The water level in the spent fuel pit must be checked periodically. The 7 day Frequency is appropriate because the volume in the spent fuel pit is normally stable. Water level changes are controlled by plant procedures and are acceptable based on operating experience.

During refueling operations, the level in the spent fuel pit is normally in equilibrium with the refueling canal and reactor cavity, and the level in the refueling reactor cavity is checked daily in accordance with SR 3.9.6.1.

(continued)

BASES

REFERENCES

1. FSAR, Section 9.5.
2. FSAR, Section 14.2.
3. 10 CFR 50.67.
4. Safety Evaluation Report (SER) for IP3 Amendment.

B 3.7 PLANT SYSTEMS

B 3.7.15 Spent Fuel Pit Boron Concentration

BASES

BACKGROUND

In the Maximum Density Rack (MDR) design, the spent fuel storage pool is divided into two separate and distinct regions. The layout of the IP3 MDR is shown in Figure B 3.7.16-1. As shown in Figure B 3.7.16-1, Region 1 (Columns SS-ZZ, Rows 35-64) includes 240 storage positions and Region 2 (Columns A-RR, Rows 1-34) includes 1105 storage positions. Region 1 is analyzed for storage of high-enrichment and low-burnup fuel. Region 2 is analyzed for storage of fuel with either higher burnup or lower enrichment. Each region has been separately analyzed for close packed storage when all cells in that region contain fuel of the highest reactivity stored in accordance with LCO 3.7.16, Spent Fuel Assembly Storage. This analysis is the basis for the restrictions on fuel storage locations established by LCO 3.7.16.

Limits, based on a combination of initial enrichment and burnup, are used to determine if a fuel assembly must be stored in region 1 or if the fuel assembly may be stored in either region 1 or region 2. Fuel with the highest initial enrichments are subject to additional restrictions even when stored in region 1. Fuel assemblies with an initial enrichment > 5.0 wt% U-235 cannot be stored in the spent fuel pit in accordance with paragraph 4.3.1.1 in Section 4.3, Fuel Storage.

The water in the spent fuel pit normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the design of both regions is based on the use of unborated water, which maintains each region in a subcritical condition during normal operation with the regions fully loaded when fuel storage locations, enrichment and burnup are in conformance with analysis assumptions as specified in LCO 3.7.16. The double contingency principle discussed in ANSI N-16.1-1975 and the April 1978 NRC letter (Ref. 1) allows credit for soluble boron under other abnormal or accident conditions, because only a single accident need be considered at one time. For example, the accident

(continued)

BASES

BACKGROUND (continued)	scenarios include movement of fuel from Region 1 to Region 2, or accidental misloading of a fuel assembly in Region 1. This event could increase the potential for criticality of the spent fuel pit. To mitigate these postulated criticality related accidents, boron concentration is verified by SR 3.7.15.1 to be within the limits specified in this LCO prior to movement of fuel assemblies in the spent fuel pit. Safe operation of the MDR with no movement of assemblies is achieved by controlling the location of each assembly in accordance with LCO 3.7.16, "Spent Fuel Assembly Storage." Prior to movement of an assembly, it is necessary to perform SR 3.7.15.1.

APPLICABLE SAFETY ANALYSES

Most accident conditions do not result in an increase in the reactivity of either of the two regions. Examples of these accident conditions are the loss of cooling (reactivity increase with decreasing water density) and the dropping of a fuel assembly on the top of the rack. However, accidents can be postulated that could increase the reactivity. This increase in reactivity is unacceptable with unborated water in the storage pool. Thus, for these accident occurrences, the presence of soluble boron in the storage pool prevents criticality in both regions. The postulated accidents are basically of two types. A fuel assembly could be incorrectly transferred from Region 1 to Region 2 (e.g., an unirradiated fuel assembly or an insufficiently depleted fuel assembly). The second type of postulated accidents is associated with a fuel assembly which is dropped adjacent to the fully loaded storage rack. This could have a small positive reactivity effect in the Region. However, the negative reactivity effect of the soluble boron compensates for the increased reactivity caused by either one of the two postulated accident scenarios. The accident analyses is described in References 2 and 3.

The concentration of dissolved boron in the spent fuel pit satisfies Criterion 2 of 10 CFR 50.36.

LCO	The spent fuel pit boron concentration is required to be ≥ 1000 ppm. The specified concentration of dissolved boron in the spent fuel pit preserves the assumptions used in the analyses of the potential critical accident scenarios as described in Reference 3. This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the spent fuel pit until a spent fuel pit verification

(continued)

BASES

LCO (continued)

confirms that there are no misloaded fuel assemblies. With no misloaded fuel assemblies and unborated water, the spent fuel pit design is sufficient to maintain the core at $K_{eff} \leq 0.95$.

The LCO is modified by a Note that states that during inter-unit transfer of fuel the spent fuel pit boron concentration must also meet Appendix C LCO 3.1.1, "Boron Concentration". This requirement ensures that the criticality analysis of the fuel within the Shielded Transfer Canister remains bounding.

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the spent fuel pit, until a complete spent fuel pit verification has been performed following the last movement of fuel assemblies in the spent fuel pit. This LCO does not apply following the verification, since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movements in progress, there is no potential for a misloaded fuel assembly or a dropped fuel assembly.

ACTIONS

A.1, A.2.1 and A.2.2

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply.

When the concentration of boron in the spent fuel pit is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. Alternatively, beginning a verification of the Spent Fuel Pit fuel locations, to ensure proper locations of the fuel, can be performed. However, prior to resuming movement of fuel assemblies, the concentration of boron must be restored. This does not preclude movement of a fuel assembly to a safe position.

(continued)

BASES

ACTIONS

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

If the LCO is not met while moving irradiated fuel assemblies in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR verifies that the concentration of boron in the spent fuel pit is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed. The 31 day Frequency is appropriate because no major replenishment of spent fuel pit water is expected to take place over such a short period of time. This SR is not required to be met or performed if a spent fuel pit verification for conformance with LCO 3.7.16, Figures 3.7.16-1 and B 3.7.16-1, has been performed on all fuel assemblies since the last verification following the last movement of fuel assemblies in the spent fuel pit.

REFERENCES

1. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

2. SER related to Amendment 173 to Facility Operating License No. DPR-64, Indian Point Nuclear Generating Unit No. 3, April 15, 1997.

3. Criticality Analysis of the Indian Point 3 Fresh and Spent Fuel Racks, Westinghouse Commercial Nuclear Fuel Division, October, 1996.

B 3.7 PLANT SYSTEMS

B 3.7.16 Spent Fuel Assembly Storage

BASES

BACKGROUND

In the Maximum Density Rack (MDR) design, the spent fuel pit (SFP) is divided into two separate and distinct regions. The layout of the IP3 MDR is shown in Figure B 3.7.16-1, IP3 Maximum Density Spent Fuel Pit Racks, Regions and Indexing. As shown in Figure B 3.7.16-1, Region 1 (i.e., Columns SS-ZZ, Rows 35-64) includes 240 storage positions and Region 2 (i.e., Columns A-RR, Rows 1-34) includes 1105 storage positions. Region 1 is analyzed for storage of high-enrichment and low-burnup fuel. Region 2 is analyzed for storage of fuel with either higher burnup or lower enrichment. Each region has been separately analyzed for close packed storage when all cells in that region contain fuel of the highest reactivity that is allowed by this LCO. This analysis is the basis for the restrictions on fuel storage locations established by this LCO.

Prior to storage in the spent fuel pit, fuel assemblies are classified as to the level of reactivity based on the initial enrichment and burnup. This classification is made using Figure 3.7.16-1, "Fuel Assembly Classification for Storage in the Spent Fuel Pit". This classification is used to determine in which region a particular fuel assembly may be stored and if additional restrictions must be applied to the assemblies in adjacent locations. Figure 3.7.16-1, "Fuel Assembly Classification for Storage in the Spent Fuel Pit", is used to classify each assembly into one of the following categories based on initial U-235 enrichment and burnup:

Type 2 assemblies are the least reactive assemblies and include any assembly for which the combination of initial enrichment and burnup places the assembly in the domain labeled Type 2 in Figure 3.7.16-1. Type 2 assemblies may be stored in any location in Region 1 or Region 2 of Figure B 3.7.16-1.

<u>Type 1A</u> assemblies are more reactive than Type 2 assemblies and include any assembly for which the combination of initial enrichment and burnup places the assembly in the domain labeled

(continued)

BASES

BACKGROUND (continued)

Type 1A in Figure 3.7.16-1. Type 1A assemblies must be stored in Region 1 of Figure B 3.7.16-1 but may be stored in any location in Region 1.

Type 1B assemblies are more reactive than Type 1A assemblies and include any assembly with an initial enrichment > 4.2 but ≤ 4.6 wt% U-235 with a burnup that places the assembly in the domain labeled Type 1B in Figure 3.7.16-1. Type 1B assemblies must be stored in Region 1 of Figure B 3.7.16-1 but may be stored in any location in Region 1 except in locations that are face-adjacent to a Type 1C assembly.

Type 1C assemblies are the most reactive bundles permitted in accordance with Specification 4.3, Fuel Storage. Type 1C assemblies include any assembly with an initial enrichment > 4.6 but ≤ 5.0 wt% U-235 with a burnup that places the assembly in the domain labeled Type 1C on Figure 3.7.16-1. Type 1C assemblies must be stored in Region 1 of Figure B 3.7.16-1. Type 1C assemblies cannot be stored in Row 64 or in Column ZZ. Additionally, Type 1C assemblies must be stored in a location where all face-adjacent locations are as follows:

a) occupied by Type 2 or Type 1A assemblies;

b) occupied non-fuel components; or, c) empty.

Fuel assemblies with an initial enrichment > 5.0 wt% U-235 are not shown on Figure 3.7.16-1 and cannot be stored in the spent fuel pit in accordance with paragraph 4.3.1.1 in Section 4.3, Fuel Storage.

The water in the spent fuel pit normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the design of both regions is based on the use of unborated water, which maintains each region in a subcritical condition during normal operation with the regions fully loaded and fuel storage locations, enrichment and burnup are in conformance with analysis assumptions and this LCO. The double contingency principle

(continued)

BASES

BACKGROUND (continued)

discussed in ANSI N-16.1-1975 and the April 1978 NRC letter (Ref. 1) allows credit for soluble boron under other abnormal or accident conditions because only a single accident need be considered at one time. For example, the accident scenarios include movement of a type 1C fuel assembly from Region 1 to Region 2, or accidental misloading of a fuel assembly in Region 1. These events could increase the potential for criticality in the Spent Fuel Pit. To mitigate these postulated criticality related accidents, boron concentration is verified to be within the limits specified in LCO 3.7.15, Spent Fuel Pit Boron Concentration, prior to movement of any fuel assembly. Safe operation of the SFP with no movement of assemblies is achieved by controlling the location of each assembly in accordance with the accompanying LCO. However, prior to movement of an assembly, it is necessary to perform SR 3.7.15.1 (i.e., verification that the spent fuel pit boron concentration is within limit).

APPLICABLE SAFETY ANALYSES

The restrictions on the placement of fuel assemblies within the spent fuel pit are based on initial enrichment and burnup which is indicative of fuel assembly reactivity. Storage locations are then restricted to ensure the k_{eff} of the spent fuel pit will always remain < 0.95, assuming the pool to be flooded with unborated water. Fuel assemblies not meeting the criteria of Figure 3.7.16-1 may not be stored in accordance with Specification 4.3.1.1 in Section 4.3.

The hypothetical accidents can only take place during or as a result of the movement of an assembly (References 2 and 3). For these accident occurrences, the presence of soluble boron in the spent fuel storage pit (controlled by LCO 3.7.15, "Spent Fuel Pit Boron Concentration") prevents criticality in both regions. By closely controlling the movement of each assembly and by checking the location of each assembly after movement, the time period for potential accidents may be limited to a small fraction of the total operating time. During the remaining time period with no potential for accidents, the operation may be under the auspices of the accompanying LCO.

The configuration of fuel assemblies in the fuel storage pit satisfies Criterion 2 of 10 CFR 50.36.

(continued)

BASES

LCO	Fuel assemblies stored in the spent fuel pit are classified in accordance with Figure 3.7.16-1 based on initial enrichment and burnup which is indicative of fuel assembly reactivity. Based on this classification, fuel assembly storage location within the spent fuel pit and storage location relative to other assemblies is restricted in accordance with the rules established by this LCO. Fuel assemblies with an initial enrichment > 5.0 wt% U-235 are not shown on Figure 3.7.16-1 because fuel assemblies with this enrichment cannot be stored in the spent fuel pit in accordance with limits established in Technical Specification Section 4.3.
APPLICABILITY	This LCO applies whenever any fuel assembly is stored in the spent fuel pit.
ACTIONS	<u>A.1</u> Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. When the configuration of fuel assemblies stored in the spent fuel pit is not in accordance with this LCO, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with this LCO. If unable to move irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If unable to move irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the action is independent of reactor operation. Therefore, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

This SR verifies by administrative means that the initial enrichment and burnup of the fuel assembly in each location is in accordance with the accompanying LCO.

REFERENCES

1. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

2. SER related to Amendment 173 to Facility Operating License No. DPR-64, Indian Point Nuclear Generating Unit No. 3, April 15, 1997.

3. Criticality Analysis of the Indian Point 3 Fresh and Spent Fuel Racks, Westinghouse Commercial Nuclear Fuel Division, October, 1996.

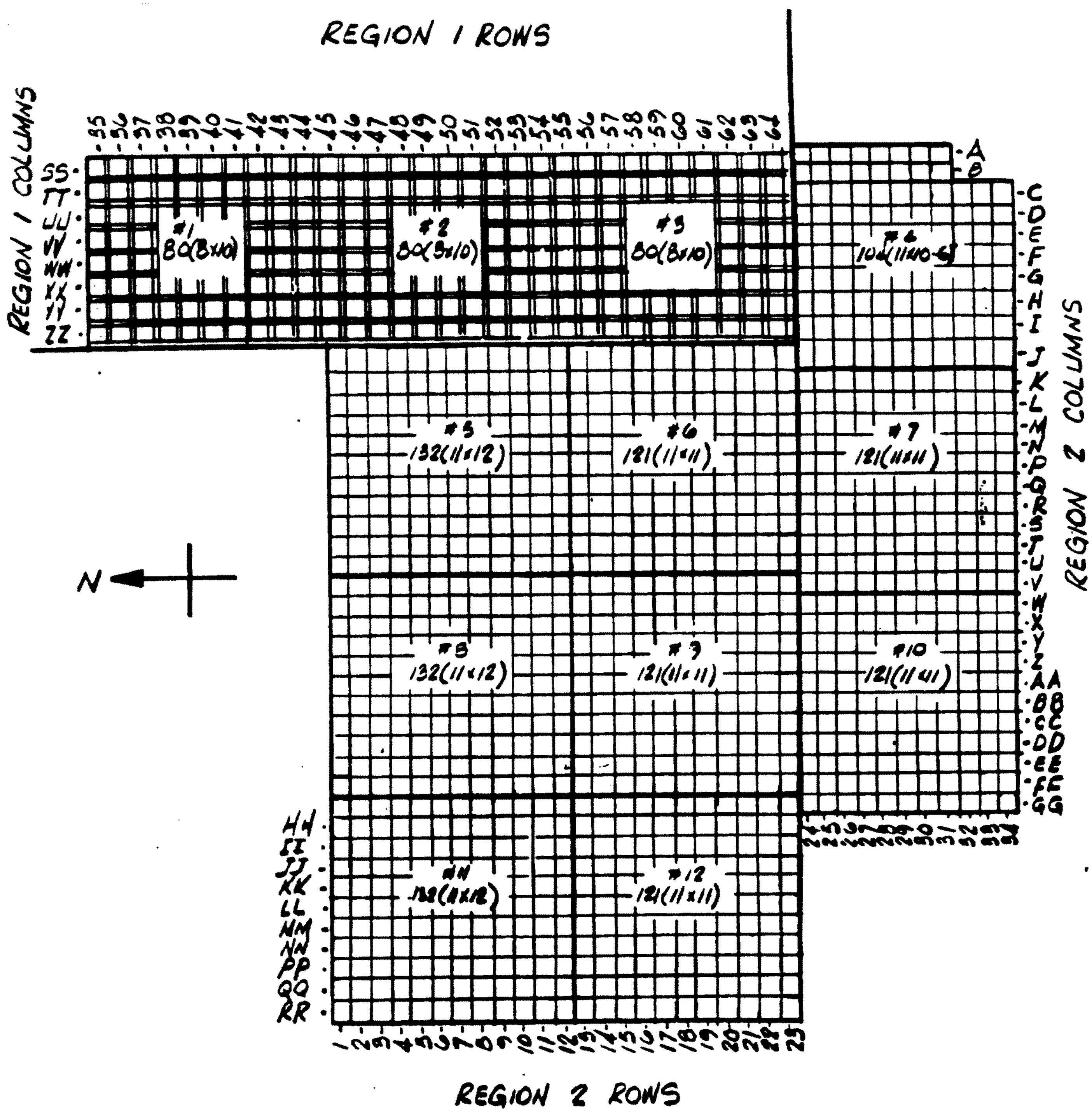

Figure B 3.7.16-1 (Page 1 of 1)
Maximum Density Spent Fuel Pit (SFP)
Racks, Regions and Indexing

B 3.7 PLANT SYSTEMS

B 3.7.17 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a 1 gpm tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of 1.0 μCi/gm (LCO 3.4.16, "RCS Specific Activity"). The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives, (i.e., $<$ 20 hours).

Operating a unit at the allowable limits could result in a 2 hour exclusion area boundary (EAB) or site boundary exposure of a small fraction (i.e., 10%) of the 10 CFR 50.67 (Ref. 1) limits or the limits established as the NRC staff approved licensing basis.

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB), as discussed in the FSAR, Chapter 14.2 (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

assumption is used in the analysis for determining the radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of an MSLB do not exceed a small fraction of the EAB (i.e., site boundary) limits (Ref. 1) for whole body and thyroid dose rates.

With the loss of offsite power, the remaining steam generators are available for core decay heat dissipation by venting steam to the atmosphere through the MSSVs and steam generator atmospheric dump valves (ADVs). The Auxiliary Feedwater System supplies the necessary makeup to the steam generators. Venting continues until the reactor coolant temperature and pressure have decreased sufficiently for the Residual Heat Removal System to complete the cooldown.

In the evaluation of the radiological consequences of this accident, the activity released from the steam generator connected to the failed steam line is assumed to be released directly to the environment. The unaffected steam generator is assumed to discharge steam and any entrained activity through the MSSVs and ADVs during the event. Credit is taken in the analysis for activity plateout or retention; however, the resultant radiological consequences represent a conservative estimate of the potential integrated dose due to the postulated steam line failure.

Secondary specific activity limits satisfy Criterion 2 of 10 CFR 50.36.

LCO

As indicated in the Applicable Safety Analyses, the specific activity of the secondary coolant is required to be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a Design Basis Accident (DBA) to a small fraction of the required limit (Ref. 1).

(continued)

BASES

LCO (continued)

Monitoring the specific activity of the secondary coolant ensures that when secondary specific activity limits are exceeded, appropriate actions are taken in a timely manner to place the unit in an operational MODE that would minimize the radiological consequences of a DBA.

APPLICABILITY

In MODES 1, 2, 3, and 4, the limits on secondary specific activity apply due to the potential for secondary steam releases to the atmosphere.

In MODES 5 and 6, the steam generators are not normally used for heat removal. Both the RCS and steam generators are depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.

ACTIONS

A.1 and A.2

DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant, is an indication of a problem in the RCS and contributes to increased post accident doses. If the secondary specific activity cannot be restored to within limits within the associated Completion Time, 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 6 hours, and in MODE 5 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 3.7.17.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131,

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SURVEILLANCE REQUIREMENTS

SR 3.7.17.1 (continued)

confirms the validity of the safety analysis assumptions as to the source terms in post accident releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. The 31 day Frequency is based on the detection of increasing trends of the level of DOSE EQUIVALENT I-131, and allows for appropriate action to be taken to maintain levels below the LCO limit.

REFERENCES

1. 10 CFR 50.67.
2. FSAR, Chapter 14.2.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources — Operating

BASES

BACKGROUND

Industry identified an issue with the frequencies of the EDG used in accident analyses (assumed 60hz) not being consistent with testing requirements for the TS. Administrative controls limit frequency to ≥ 59.7 Hz and ≤ 60.3 Hz (see Calculation IP3-CALC-ED-00207). The Operations surveillance procedures 3-PT-M079 and 3-PT-R160 verify steady state frequency meets the proposed TS frequency range of ≥ 59.7 Hz and ≤ 60.3 Hz.

The unit Electrical Power Distribution System AC sources consist of the following: two offsite circuits (the normal or 138 kV circuit and the alternate or 13.8 kV circuit), each of which has a preferred and backup feeder; and, the onsite standby power circuit consisting of three diesel generators. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite plant distribution system is configured around 6.9 kV buses Nos. 1, 2, 3, 4, 5, and 6. All offsite power to safeguards buses enter the plant via 6.9 kV buses Nos.5 and 6 which are connected to the 138 kV (normal) offsite circuit and have the ability to be connected to the 13.8 kV (alternate) offsite circuit. 6.9 kV buses 1, 2, 3, and 4, which supply power to the 4 reactor coolant pumps (RCPs), typically receive power from the main generator via the unit auxiliary transformer (UAT) when the plant is at power. However, when the main generator or UAT is not capable of supporting this arrangement, 6.9 kV buses 1 and 2 receive offsite power via 6.9 kV bus 5 and 6.9 kV buses 3 and 4 receive offsite power via 6.9 kV bus 6. Following a unit trip, 6.9 kV buses 1, 2, 3, and 4 will auto transfer (fast transfer) to 6.9 kV buses 5 and 6 in order to receive offsite power. The 6.9 kV buses supply power to the 480 V buses using 6.9 kV/480 V station service transformers (SSTs) as follows: 6.9 kV bus 5 supplies 480 V bus 5A via SST 5; 6.9 kV bus 6 supplies 480 V bus 6A via SST 6; 6.9 kV bus 2 supplies 480 V bus 2A via SST 2; and, 6.9 kV bus 3 supplies 480 V bus 3A via SST 3.

The onsite AC Power Distribution System begins with 480 V buses 5A, 6A, 2A and 3A and is divided into 3 safeguards power trains (trains) consisting of the 480 volt safeguards bus(es) and associated AC electrical power distribution subsystems, 125 volt DC bus subsystems, and 120 volt vital AC instrument bus subsystems. The three trains are designed such that any two trains are capable of meeting minimum requirements for accident mitigation and/or safe shutdown. The three safeguards power trains are train 5A (480 volt bus 5A and associated DG 33), train 6A (480 volt bus 6A and associated DG 32), and train 2A/3A (480 volt buses 2A and 3A and associated DG 31).

(continued)

BASES

BACKGROUND (continued)

Offsite power is supplied to the plant from the transmission network by two electrically and physically separated circuits, the 138 kV or normal circuit and the 13.8 kV or alternate circuit. Each of the offsite circuits from the Buchanan substation into the plant is required to be supported by a physically independent circuit from the offsite network into the Buchanan substation. All offsite power enters the plant via 6.9 kV buses Nos.5 and 6 which are connected to the 138 kV (normal) offsite circuit and have the ability to be connected to the 13.8 kV (alternate) offsite circuit. This arrangement satisfies the requirement that at least one of the two required circuits can within a few seconds, provide power to safety-related equipment following a loss-of-coolant accident. Operator action is required to supply offsite power to the plant using the 13.8 kV (alternate) offsite source.

The 138 kV circuit and the 13.8 kV circuit each have a preferred and a backup feeder that connects the circuit to the Buchanan substation. For both the 138 kV and 13.8 kV circuits, the preferred IP3 feeder is the backup IP2 feeder and the backup IP3 feeder is the preferred IP2 feeder.

For the 138 kV (i.e., normal) offsite circuit, IP2 and IP3 each have a dedicated Station Auxiliary Transformer (SAT) that can be supplied by either a preferred or backup feeder. The normal or 138 kV offsite circuit, including the SAT used exclusively for IP3, is designed to supply all IP3 loads, including 4 operating RCPs and ESF loads, when using either the preferred (95331) or backup (95332) feeder. There are no special restrictions when IP2 and IP3 are both using the same 138 kV feeder concurrently.

For the 13.8 kV (i.e., alternate) offsite circuit, there is a 13.8 kV/6.9 kV auto-transformer associated with feeder 13W92 and a 13.8 kV/6.9 kV auto-transformer associated with feeder 13W93.

Feeder 13W93 and its associated auto-transformer is the preferred feeder for the IP3 alternate (13.8 kV) circuit and the backup feeder for the IP2 alternate (13.8 kV) circuit. Feeder 13W92 and its associated auto-transformer is the backup feeder for the IP3 alternate (13.8 kV) circuit and the preferred feeder for the IP2 alternate (13.8 kV) circuit.

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite 480 V ESF bus(es).

Open Phase Detection (OPD) systems are installed to monitor Open Phase Conditions (OPC) on both 139kV and 13.8kV offsite feeder circuits. These detection systems are in place to function as a support system to the offsite

(continued)

BASES

BACKGROUND (continued)

power sources. Detection of an open phase will remove the inoperable offsite source to allow for backup feeders to supply the ESF loads.

The onsite standby power source consists of 3 480 V diesel generators (DGs) with a separate DG dedicated to each of the safeguards power trains. Safeguards power train 5A (480 V bus 5A) is supported by DG 33; safeguards power train 6A (480 V bus 6A) is supported by DG 32; and, safeguards power train 2A/3A (480 V buses 2A and 3A) is supported by DG 31. A DG starts automatically on a safety injection (SI) signal or on an ESF bus undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, an undervoltage signal strips nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by individual load timers. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

In the event of a loss of 138 kV or normal offsite source, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for DGs 31, 32 and 33 are consistent with the requirements of Regulatory Guide 1.9 (Ref. 3). The 3 DGs each consist of an Alco model 16-251-E engine coupled to a Westinghouse 2188 kVA, 0.8 power factor, 900 rpm, 3 phase, 60 cycle, 480 volt generator. The ESF loads that are powered from the 480 V ESF buses are listed in Reference 2.

(continued)

BASES

BACKGROUND (continued)

The EDGs have four capacity ratings as defined below that can be used to assess EDG operability.

Continuous: Electrical power output capability that can be maintained 24 hours /day, with no time constraint.

2000-hour: Electrical power output capability that can be maintained in one continuous run of 2000 hours or in multiple shorter duration runs totaling 2000 hours.

2-hour: Electrical power output capability that can be maintained for up to 2 hours in any 24-hour period.

1/2 - hour: Electrical power output capability that can be maintained for up to 30 minutes in any 24-hour period.

The electrical output capabilities (EDG load) applicable to these four ratings are as follows:

RATING	EDG LOAD	TIME CONSTRAINT
Continuous	≤ 1750 kW	None
2000-hour	≤ 1950 kW	≤ 2000 hours / calendar year
2-hour	≤1950 kW	≤ 2 hours in a 24-hour period; AND
	≤ 1750 kW	for the remaining 22 hours. [See NOTE A]
1/2-hour	≤2000 kW	≤ 30 minutes in a 24-hour period; AND
	≤1750 kW	for the remaining 23.5 hours. [See NOTE A]

NOTE A: The loading cycle permitted for the '2-hour' and the '1/2-hour' rating is operation at the overload condition (e.g. > 1750 kW) for the specified time followed by operation at the 'continuous' (e.g. ≤1750kW) rating for the remaining time in the 24-hour period. This loading cycle may be repeated each day, as long as back-to-back operation in the overload condition does not occur. The 2000-hour cumulative time constraint also applies to repetitive operation at the overload conditions allowed by the 2-hour and the 1/2-hour ratings.

(continued)

BASES

BACKGROUND (continued)

Operation in excess of 2000 kW, regardless of the duration, is an unanalyzed condition. In such cases, the EDG is assumed to be inoperable and the vendor should be consulted to determine if accelerated or supplemental inspection and/or maintenance is necessary. The EDG can be returned to an operable status following completion of vendor-required inspection and/or maintenance.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the Accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least 2 of the 3 safeguards power trains energized from either onsite or offsite AC sources during Accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36.

(continued)

LCO

Two qualified circuits between the offsite transmission network and the onsite Electrical Power System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

There are two qualified circuits (normal and alternate) from the transmission network at the Buchanan Station to the onsite electric distribution system. The normal circuit is 138 kV and the alternate circuit is 13.8 kV. If the alternate circuit is in use, the normal circuit is inoperable because the autotransfer functions mentioned in the following circuit descriptions are disabled. Both of these circuits must be supported by a circuit from the offsite network into the Buchanan substation that is physically independent from the other circuit to the extent practical. The circuits into the Buchanan substation that satisfy these requirements are 96951, 96952 and 95891.

The 138 kV (i.e., normal) offsite circuit consists of one of the following: 138 kV feeder 95331 (preferred); or, 138 kV feeder 95332 (backup). Additionally, the 138 kV/6.9 kV station auxiliary transformer, circuit breakers ST5 and ST6 which supply 6.9 kV buses 5 and 6, and the following components which are common to the normal and alternate offsite circuits:

a. The 480 V bus 5A supply consisting of 6.9 kV bus 5, station service transformer 5, and circuit breakers SS5 and 52/5A;

b. The 480 V bus 2A supply consisting of 6.9 kV bus 5, circuit breaker UT2-ST5 (including autotransfer function), 6.9 kV bus 2, station service transformer 2, and circuit breakers SS2 and 52/2A;

c. The 480 V bus 6A supply consisting of 6.9 kV bus 6, station service transformer 6, and circuit breakers SS6 and 52/6A; and,

d. The 480 V bus 3A supply consisting of 6.9 kV bus 6, circuit breaker UT3-ST6 (including autotransfer function), 6.9 kV bus 3, station service transformer 3, and circuit breakers SS3 and 52/3A.

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BASES

LCO (continued)

The 13.8 kV (i.e., alternate) offsite circuit consists of one of the following: 13.8 kV feeder 13W93 and its associated 13.8/6.9 kV autotransformer (preferred); or, 13.8 kV feeder 13W92 and its associated 13.8/6.9 kV autotransformer (backup). Circuit breakers GT35 and GT36, which supply 6.9 kV buses 5 and 6, and the following components are common to the normal and alternate offsite circuits:

a. The 480 V bus 5A supply consisting of 6.9 kV bus 5, station service transformer 5, and circuit breakers SS5 and 52/5A;

b. The 480 V bus 2A supply consisting of 6.9 kV bus 5, circuit breaker UT2-ST5 (not including autotransfer function), 6.9 kV bus 2, station service transformer 2, and circuit breakers SS2 and 52/2A;

c. The 480 V bus 6A supply consisting of 6.9 kV bus 6, station service transformer 6, and circuit breakers SS6 and 52/6A; and,

d. The 480 V bus 3A supply consisting of 6.9 kV bus 6, circuit breaker UT3-ST6 (not including autotransfer function), 6.9 kV bus 3, station service transformer 3, and circuit breakers SS3 and 52/3A.

If the alternate (13.8 kV) offsite circuit is being used to supply power to the plant and the Unit Auxiliary Transformer is supplying 6.9 kV bus 1, 2, 3 or 4, the size of the 13.8 kV/6.9 kV auto-transformers requires that the automatic transfer of 6.9 kV buses 1, 2, 3, and 4 to 6.9 kV buses 5 and 6 (i.e., the offsite circuit) be disabled because neither 13.8 kV/6.9 kV auto-transformer is capable of supplying 4 operating RCPs. This requirement is not intended to preclude supplying 6.9 kV buses 1, 2, 3, and 4 using the alternate offsite circuit via the 13.8 kV/6.9 kV auto-transformers once sufficient loads have been stripped from 6.9 kV buses 1, 2, 3, and 4 to assure that the 13.8 kV/6.9 kV auto-transformer will not be overloaded by these manual actions.

If IP3 and IP2 are both using a single 13.8 kV feeder (13W92 or 13W93), administrative controls are used to ensure that the 13.8 kV/6.9 kV auto-transformer load restrictions will not be exceeded.

Operability of the offsite power sources requires the ability to provide the required capacity during design basis conditions. The minimum offsite voltage necessary to provide the required capacity was determined, using

(continued)

BASES

LCO (continued)

system load flow studies with conservative assumptions (Reference 10), to be greater than or equal to 136 kV and 13.4 kV for the 138 kV and 13.8 kV circuits, respectively. Upon notification by Con Ed that these alarm limits are not met, the LCO is considered not met at the time of the initial alarm. When the grid monitoring system is operating the minimum acceptable 138 kV voltage varies with grid conditions and Con Ed will provide notification.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

Three DGs must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses.

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

The AC sources in each safeguards power train must be separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus, and not violate separation criteria. A circuit that is not connected to an ESF bus is required to have OPERABLE automatic or manual transfer capability to the ESF buses to support OPERABILITY of that circuit.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and
b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources — Shutdown."

(continued)

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG or the 138 kV offsite circuit. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG. This also applies to the 138 kV offsite circuit, which is the only immediate access offsite circuit. Therefore, the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on a more frequent basis. For activities that will require entry into the associated Condition, performance of SR 3.8.1.1 for the offsite circuit(s) could be completed up to 8 hours prior to entry into the Condition. Performance of this SR before entry into the Condition can be credited to establish the accelerated Frequency and therefore is equivalent to performing the SR within 1 hour after entry into the Condition. The LCO Bases describes the components and features which comprise the offsite circuits. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met.

However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, applies only if the 13.8 kV offsite power circuit is being used to feed 6.9 kV buses 5 and 6 and the UAT is supplying 6.9 kV bus 1, 2, 3 or 4. This action prevents the automatic transfer of 6.9 kV buses 1, 2, 3, and 4 from the UAT to offsite power after a unit trip. Transfer of buses 1, 2, 3, and 4 from the UAT to offsite power could result in overloading the 13.8 kV/6.9 kV autotransformer. This requirement is not intended to preclude supplying 6.9 kV buses 1, 2, 3, and 4 using the alternate offsite circuit via the 13.8 kV/6.9 kV auto-transformers once sufficient loads have been stripped from 6.9 kV buses 1, 2, 3, and 4 to assure that the 13.8 kV/6.9 kV auto-transformer will not be overloaded by these manual actions. Automatic transfer of buses 1, 2, 3, and 4 can be disabled by placing 6.9 kV bus tie breaker control switches 1-5, 2-5, 3-6, and 4-6 in the "pull-out" position.

(continued)

BASES

ACTIONS

A.2 (continued)

Although the auto-transfer feature is normally disabled prior to placing the 13.8 kV offsite power circuit in service, a Completion Time of 1 hour ensures that the 13.8 kV circuit meets requirements for Operability promptly when the alternate offsite circuit is configured to support the response of ESF functions.

A.3

Required Action A.3, which only applies if the train will not be powered automatically from an offsite source when the main turbine generator trips, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of redundant required features. Required safety features are designed with a redundant safety feature that is powered from a different safeguards power train.

Therefore, if a required safety feature is supported by an inoperable offsite circuit, then the failure of the DG associated with that required safety feature will not result in the loss of a safety function because the safety function will be accomplished by the redundant safety feature that is powered from a different safeguards power train. However, if a required safety feature is supported by an inoperable offsite circuit and the redundant safety feature that is powered from a different safeguards power train is also inoperable, then the failure of the DG associated with that required safety feature will result in the loss of a safety function. Required Action A.3 ensures that appropriate compensatory measures are taken for a Condition where the loss of a DG could result in the loss of a safety function when an offsite circuit is not OPERABLE.

The turbine driven auxiliary feedwater pump is not required to be considered a redundant required feature, and, therefore, not required to be determined OPERABLE by this Required Action, because the design is such that the remaining OPERABLE motor driven auxiliary feedwater pump(s) is capable (without any reliance on the motor driven auxiliary feedwater pump powered by the emergency bus associated with the inoperable diesel generator) of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

(continued)

BASES

ACTIONS

A.3 (continued)

The Completion Time for Required Action A.3 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. The train will not have offsite power automatically supplying its loads following a trip of the main turbine generator; and

b. A required feature powered from another safeguards power train is inoperable.

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

Discovering that offsite power is not automatically available to one train of the onsite Electrical Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the two remaining safeguards power trains of the onsite Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and

(continued)

BASES

ACTIONS

A.4 (continued)

the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Distribution System.

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

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the offsite circuits on a more frequent basis. For activities that will require entry into the associated Condition, performance of SR 3.8.1.1 for the offsite circuit(s) could be completed up to 8 hours prior to entry into the Condition. Performance of this SR before entry into the Condition can be credited to establish the accelerated Frequency and therefore is equivalent to performing the SR within 1 hour after entry into the Condition. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of redundant required features. Required safety features are designed with a redundant safety feature that is powered from a different safeguards power train. Therefore, if a required safety feature is supported by an inoperable DG, then the failure of the offsite circuit will not result in the loss of a safety function because the safety function will be accomplished by the redundant safety feature that is powered from a different safeguards power train (and DG). However, if a required safety feature is supported by an inoperable DG and the redundant safety feature that is powered from a different safeguards power train is also inoperable, then a loss of offsite power will result in the loss of a safety function. Required Action B.2 ensures that appropriate compensatory measures are taken for a Condition where the loss of offsite power could result in the loss of a safety function when a DG is not OPERABLE.

(continued)

BASES

ACTIONS

B.2 (continued)

The turbine driven auxiliary feedwater pump is not required to be considered a redundant required feature, and, therefore, not required to be determined OPERABLE by this Required Action, because the design is such that the remaining OPERABLE motor driven auxiliary feedwater pumps is capable (without any reliance on the motor driven auxiliary feedwater pump powered by the emergency bus associated with the inoperable diesel generator) of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature powered from another safeguards power train is inoperable.

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

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

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

(continued)

BASES

ACTIONS (continued)

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DG(s). If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DGs, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

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

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

B.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours.

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Distribution System. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. Two offsite circuits are inoperable when both the immediate access circuit and the delayed offsite circuit are not available to one or more safeguards power trains. The most probable cause is a failure in a portion of the circuit that is common to both offsite circuits. The Completion Time for this failure of redundant required features is reduced to 12 hours from

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

that allowed for one train without offsite power (Required Action A.3). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that three complete safeguards power trains are OPERABLE. When a redundant required feature is not OPERABLE, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps. Single train features, such as turbine driven auxiliary pumps, are included as discussed in the Bases for Required Action A.3. The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

In this Required Action the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours.

This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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

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

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient.

In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Reference 6, with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours.

If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. When the UAT is being used to supply 6.9 kV buses 1, 2, 3 0r 4 and the 13.8 kV offsite circuit is being used to supply 6.9 kV buses 5 and 6, the autotransfer function is disabled. Therefore, 480 V safeguards buses 2A and 3A (safeguards train 2A/3A) will not be automatically re-energized with offsite power following a plant trip until connected to the offsite circuit by operator action. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no offsite or DG AC power source automatically available to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems — Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG, without regard to whether a train would be de-energized during an event. LCO 3.8.9 provides the appropriate restrictions for a train that would be de-energized.

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BASES

ACTIONS

D.1 and D.2 (continued)

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure.

The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

E.1

With two or more DGs inoperable, the remaining standby AC sources are not adequate to satisfy analysis assumptions. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with two or more DGs inoperable, operation may continue for a period that should not exceed 2 hours.

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BASES

ACTIONS (continued)

F.1 and F.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 11). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 11, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action F.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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 plant systems.

(continued)

BASES

ACTIONS (continued)

G.1 and H.1

Conditions G and H correspond to a level of degradation in which all redundancy in the AC electrical power supplies has been lost or a loss of safety function has already occurred. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 1). 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 consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 8).

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 422 V is the value determined to be acceptable in the analysis of the degraded grid condition. This value allows for voltage drop to the terminals of 480 V motors. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating.

The specified maximum steady state output voltage of 500 V is equal to the maximum operating voltage specified for 480 V circuit breakers. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ±2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The verification includes a sufficient number of breakers in their correct position together with proper bus voltage to ensure that distribution buses and loads are appropriately connected to either their

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 (continued)

preferred or backup power source for each of the offsite circuits (Normal and Alternate), and that appropriate independence of offsite circuits is maintained. Portions of this SR may require telephone communication with the District Operator or IP2 Control Room personnel capable of confirming the status of the offsite circuits or some breaker positions. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because 6.9 kV bus status and 13.8 kV circuit status are displayed in the control room.

An Open Phase Condition (OPC) is created when there is not proper circuit continuity or breaker alignment for one or more phases of an offsite source. Open Phase Conditions (OPC) on both 139kV and 13.8kV offsite feeder circuits. These detection systems are in place to function as a support system to the offsite power sources. Detection of an open phase will remove the inoperable offsite source to allow for backup feeders to supply the ESF loads.

SR 3.8.1.2

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period.

For the purposes of SR 3.8.1.2, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

SR 3.8.1.2 requires that, at a 31 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the FSAR, Chapter 14 (Ref. 5).

The normal 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). This Frequency provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing. DGs have redundant air start motors and both air start motors are actuated by both channels of the start logic. The DG is OPERABLE when either air start

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

motor is OPERABLE; however, this SR will not demonstrate that both of the air start motors are independently capable of starting the DG. If an air start motor is not capable of performing its intended function, a DG is inoperable until a timed start is conducted using the remaining air start motor. Alternately, this SR may be performed using one air start motor (i.e., redundant air start motor isolated) on a staggered basis to ensure that the DG will start with either air start motor.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads of 90% to 100% of the 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 the 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

This SR is modified by four Notes. Note 1 indicates 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 states that momentary transients, because of changing bus loads, do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for approximately 1 hour of DG operation at full load.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

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.

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 the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 8). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the 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. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The design of fuel transfer systems is such that pumps operate automatically or must be started manually 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 appropriate. Since proper operation of fuel transfer systems is an inherent part of DG OPERABILITY, the Frequency of this SR is consistent with the 31 day Frequency for verification of DG operability.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.7

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

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown or startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.8

Verification that 6.9 kV buses 2 and 3 will auto transfer (fast transfer) from the Unit Auxiliary transformer to 6.9 kV buses 5 and 6 (i.e. station auxiliary transformer) following a loss of voltage on 6.9 kV buses 2 and 3 is needed to confirm the Operability of a function assumed to operate to provide offsite power to safeguards power train 2A/3A following a trip of the main generator.

An actual demonstration of this feature requires the tripping of the main generator while the reactor is at power with the main generator supplying 6.9 kV buses 2 and 3. This will cause perturbations to the electrical distribution systems that could challenge unit safety systems during a plant shutdown.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

Therefore, in lieu of actually initiating a circuit transfer, testing that adequately shows the capability of the transfer is acceptable. This transfer testing may include any sequence of sequential, overlapping, or total steps so that the entire transfer sequence is verified. The 24 month Frequency is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length.

This SR is modified by two Notes. The reason for Note 1 is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown or startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR. As stated in Note 2, this SR is only required to be met when the 138 kV offsite circuit is supplying 6.9 kV buses 5 and 6 because, if the 13.8 kV circuit is supplying 6.9 kV buses 5 and 6, then the feature tested by this SR is required to be disabled.

SR 3.8.1.9

This Surveillance demonstrates that DG noncritical protective functions are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal, and critical protective functions (engine overspeed, low lube oil pressure, and engine overcrank) trip the DG to avert substantial damage to the DG unit. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

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

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DG from service. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown or startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.10

IEEE-387-1995 (Ref. 9) requires demonstration once per 24 months that the DGs can start and run continuously at full load capability for an interval of not less than 8 hours, > 105 minutes of which is at a load equivalent to 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating 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 of ≤ 0.85 for EDG 31, ≤ 0.87 for EDG 32, and, ≤ 0.84 for EDG 33. These power factors were chosen to be representative of the actual design basis inductive loading that the DG would experience. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

recommendations in order to maintain DG OPERABILITY.

The 24 month Frequency is consistent with the recommendations of Ref. 9, and takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by four Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the power factor limit will not invalidate the test. 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 unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown or startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Note 3 ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.85 for EDG 31, ≤ 0.87 for EDG 32, and, ≤ 0.84 for EDG 33. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. Under certain conditions, however, Note 3 allows the surveillance to be conducted at a power factor other than ≤ 0.85 for EDG 31, ≤ 0.87 for EDG 32, and, ≤ 0.84 for EDG 33. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤0.85 for EDG 31, ≤ 0.87 for EDG 32, and, ≤ 0.84 for EDG 33 results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.85 for EDG 31, 0.87 for EDG 32, and, 0.84 for EDG 33 while still maintaining acceptable voltage limits on the emergency busses.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power factor of 0.85 for EDG 31, 0.87 for EDG 32, and, 0.84 for EDG 33 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained close as practicable to 0.85 for EDG 31, 0.87 for EDG 32, and, 0.84 for EDG 33 without exceeding the DG excitation limits. Note 4 recognizes that there is greater difficulty in meeting the power factors while tied to the 13.8 kV offsite power and requires an assessment to ascertain whether the power factors can be reasonably met.

SR 3.8.1.11

Under accident conditions with concurrent loss of offsite power, loads are sequentially connected to the bus by individual load timers to prevent overloading of the DGs due to high motor starting currents. The design load sequence time interval tolerance ensure 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. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is based on engineering judgment, taking into consideration operating experience that 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 a Note that specifies that load timers associated with equipment that has automatic initiation capability disabled are not required to be OPERABLE. This note is needed because these time delay relays affect the OPERABILITY of both the AC sources (offsite power and DG) and the specific load that the relay starts. If a timer fails to start a required load or starts the load later than assumed in the analysis, then the required load is not OPERABLE. If a timer starts the load outside the design interval (early or late), then the DG and offsite source are not OPERABLE because overlap of equipment starts may cause an offsite source to exceed limits for voltage or current or a DG to exceed limits for voltage, current or frequency. Therefore, when an individual load sequence timer is not OPERABLE, because the timing sequence is outside the design interval, Condition D must be entered. However, if the automatic initiation capability of the affected load is disabled, Condition D may be exited, and the Actions for the inoperable load are taken. It is conservative to disable the automatic

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

initiation capability of a component rather than continue with the associated DG inoperable because of the following: the potential for adverse impact on the DG by simultaneous start of ESF equipment is eliminated; all other loads powered from the safeguards power train are available to respond to the event; and, the load with the inoperable timer remains available for a manual start after the one minute completion of the normal starting sequence.

SR 3.8.1.12

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

This Surveillance demonstrates the DG operation during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. This SR verifies all actions encountered from an ESF signal concurrent with the loss of offsite power, including shedding of the 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.

The DG autostart time of 10 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 is achieved.

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, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated, or residual heat removal (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 connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

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

This SR is modified by three 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, that is, with the engine coolant and oil and temperature maintained and lube oil continuously circulated consistent with manufacturer recommendations for DGs.

The reason for Note 2 is that the performance of the Surveillance would remove required offsite circuits from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance: as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown or startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment.

The reason for Note 3 is to allow the SR to be conducted with only one safeguards train at a time or with two or three safeguards trains concurrently. Allowing the LOOP/LOCA test to be conducted using one safeguards power train and one DG at a time is acceptable because the safeguards power trains are designed to respond to this event independently. Therefore, an individual test for each safeguards power train will provide an adequate verification of plant response to this event.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

Simultaneous testing of all three safeguards power trains is acceptable as long as the following plant conditions are established:

- All three DGs are available,
- diverse and redundant decay heat removal is available,
- no offsite power circuits are inoperable, and
- no simultaneous activities are performed that are precursors to events requiring AC power for mitigation (e.g., fuel handling accident or inadvertent RCS draindown)

SR 3.8.1.13

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is to allow SR 3.8.1.12 to satisfy the requirements of this SR if SR 3.8.1.12 is performed with more than one safeguards power train concurrently.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Chapter 8.

3. Regulatory Guide 1.9, Rev. 3, July 1993.

4. FSAR, Chapter 6.

5. FSAR, Chapter 14.

(continued)

BASES

REFERENCES (continued)

6. Regulatory Guide 1.93, Rev. 0, December 1974.

7. Generic Letter 84-15, Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability.

8. Regulatory Guide 1.137, Rev. 0, 1978.

9. IEEE Standard 387-1995, IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations.

10. Calculation IP3-CALC-ED-03158, Dated March 28, 2005.

11. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources — Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources — Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

during shutdown conditions are allowed by the LCO for required systems. During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability to support systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite diesel generator (DG) power.

The AC sources satisfy Criterion 3 of 10 CFR 50.36.

(continued)

BASES

LCO

One offsite circuit capable of supplying the onsite power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems—Shutdown," ensures that all required loads are powered from offsite power. Two OPERABLE DGs, associated with the distribution system train required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DGs ensures the availability of sufficient AC sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents). Under specific plant conditions the number of required operable DGs may be reduced to one. The plant conditions described by the LCO ensures that ample time is available for operator actions in response to a loss of offsite power. When one residual heat removal (RHR) loop is required to be OPERABLE and in operation, and one RHR loop is required to be OPERABLE, the RHR loop that is OPERABLE but not operating needs to be capable of being powered in the event the operating RHR loop fails. However, only the operating RHR loop needs to be capable of being powered from an onsite AC electrical power distribution subsystem associated with an OPERABLE diesel.

The offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the Engineered Safety Feature (ESF) bus(es). Offsite circuits are those that are described in the Bases of LCO 3.8.1, AC Sources - Operating, except that safeguards power trains may be cross connected when in MODES 5 and 6.

Open Phase Detection (OPD) systems are installed to monitor Open Phase Conditions (OPC) on both 139kV and 13.8kV offsite feeder circuits. These detection systems are in place to function as a support system to the offsite power sources. Detection of an open phase will remove the inoperable offsite source to allow for backup feeders to supply the ESF loads.

The DGs must be capable of starting, accelerating to rated speed and voltage, and connecting to their

(continued)

BASES

LCO (continued)

respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. The DG must be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses.

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

It is acceptable for safeguards power trains to be cross tied during shutdown conditions, allowing a single offsite power circuit to supply all required trains. In this case, interlocks
that disconnect the affected tie breakers before DGs are automatically connected to the bus must be OPERABLE.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

ACTIONS

A.1

An offsite circuit would be considered inoperable if it

(continued)

ACTIONS

A.1 (continued)

were not available to one required safeguards power train. Although two safeguards power trains may be required by LCO 3.8.10, the one train with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required features inoperable, with no offsite power available, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

A.2.1, A.2.2, A.2.3 and A.2.4

With the offsite circuit not available to all required trains, the option would still exist to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions. The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SDM is maintained.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System's ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with

(continued)

ACTIONS

A.2.1, A.2.2, A.2.3 and A.2.4 (continued)

no AC power to any required ESF bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit, whether or not a train is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized bus.

B.1, B.2, B.3 and B.4

Condition B is entered when any required DGs are inoperable. A DG would be considered inoperable if it could not support its associated safeguards power train. When LCO 3.8.2.b.1 applies, 2 DGs are required to be OPERABLE. In this case, whether one or both of the required DGs is inoperable, the minimum required diversity of AC power sources is not available to required features. Therefore, it is required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactive additions.

When specific limitations are satisfied, as stated in LCO 3.8.2.b.2, only one DG is required. The additional restrictions on plant conditions for requiring only one DG provides ample time for operator action, in the event of a loss of offsite power, to manually restore decay heat removal capability. The combination of subcritical duration, fuel location, and refueling cavity water level results in a time period of at least 3 hours for heatup of this water inventory from 140 ^{0}F to 200 ^{0}F.

With any required DGs inoperable, the Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SDM is maintained. Additionally, Required Actions B.1, B.2, and B.3 do not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of postulated events.

Furthermore, when Required Actions B.1, B.2 and B.3 are implemented, it is required to immediately initiate action (B.4) to restore the required DG(s) and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt

(continued)

ACTIONS

B.1, B.2, B.3 and B.4 (continued)

attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, 3, and 4. SR 3.8.1.8 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.9 is not required to be met because the DG automatic trips are bypassed only on the safety injection start signal, not on the loss of power start signal. SR 3.8.1.13 is excepted because starting independence is not required with the DG(s) that is not required to be operable.

This SR is modified by two Notes. The reason for the first Note is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude deenergizing a required 480 V ESF bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

The reason for the second Note is that SR 3.8.1.12 includes testing with an actual or simulated ESF actuation signal. ESF actuation is not required in MODES 5 and 6 so that this portion of the surveillance is not required to be met.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil and Starting Air

BASES

BACKGROUND

Fuel oil for the safeguards DGs is stored in three 7,700 gallon DG fuel oil storage tanks located on the south side of the Diesel Generator Building. The offsite DG fuel oil reserve is maintained in two 30,000 gallon tanks located in the Indian Point 1 Superheater Building and/or a 200,000 gallon tank in the Buchanan Substation which is located in close proximity to the IP3 site. The IP3 offsite fuel oil reserve is maintained by the operators of IP2, in accordance with formal agreements. The IP3 offsite DG fuel oil reserve is normally stored in the same tanks used to store the IP2 offsite DG fuel oil reserve.

Sufficient fuel for at least 48 hours of minimum safeguards equipment operation is available when any two of the DG fuel oil storage tanks are available and each contains 5,365 usable gallons of fuel oil. Additional margin is provided by 115 gallons of fuel oil in the DG day tank required by SR 3.8.1.4. The maximum DG loadings for design basis transients that actuate safety injection are summarized in FSAR 8.2 (Ref. 1). These transients include large and small break loss of coolant accidents (LOCA), main steamline break and steam generator tube rupture (SGTR).

The three DG fuel oil storage tanks are filled through a common fill line that is equipped with a truck hose connection and a shutoff valve at each tank. The overflow from any DG fuel oil storage tank will cascade into an adjacent tank. Each DG fuel oil storage tank is equipped with a single vertical fuel oil transfer pump that discharges to either the normal or emergency header. Either header can be used to fill the day tank at each diesel. Each DG fuel oil storage tank has an alarm that sounds in the control room when the level in the tank approaches the level equivalent of the minimum required usable inventory. Each tank is also equipped with a sounding connection and a level indicator.

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BACKGROUND (continued)

Each emergency diesel is equipped with a 175-gallon day tank with an operating level that provides sufficient fuel for approximately one hour of DG operation. A decrease in day tank level to approximately 115 gallons (65% full) will cause the normal and emergency fill valves on that day tank to open and the transfer pump in the corresponding DG fuel oil storage tank to start. Once started, the pump will continue to run until that day tank is filled. However, any operating transfer pump will fill any day tank with a normal or emergency fill valve that is open. When a day tank is at approximately 158 gallons (90% full), a switch initiates closing of the day tank normal and emergency fill valves.

Technical Specifications require sufficient fuel oil to operate 2 of the 3 required DGs at minimum safeguards load for 7 days. The Technical Specification required volume of fuel oil includes the 26,826 gallons of usable fuel oil in the reserve tanks, and 10,730 usable gallons in two DG fuel oil storage tanks (assuming a failure makes the oil in the third DG fuel oil storage tank unavailable), without crediting the additional margin of 230 gallons in two day tanks (assuming a failure makes the oil in the day tank associated with the third DG unavailable).

If the DGs require fuel oil from the fuel oil reserve tank(s), the fuel oil will be transported by truck to the DG fuel oil storage tanks. A truck with appropriate hose connections and capable of transporting oil is available either on site or at the Buchanan Substation. Commercial oil supplies and trucking facilities are also available in the vicinity of the plant.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Requirements for DG fuel oil testing methodology, frequency, and acceptance criteria are maintained in the program required by Specification 5.5.12, Diesel Fuel Oil Testing Program.

Each DG has an air start system with adequate capacity for four successive start attempts on the DG without recharging the air start receiver(s). The air starting system is designed to shutdown and lock out any engine which does not start during the initial start attempt so that only enough air for one automatic start is used. This conserves air for subsequent DG start attempts.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 3), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

Since diesel fuel oil and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36.

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of operation for 2 of 3 DGs at minimum safeguards load. Fuel oil is also required to meet specific standards for quality. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources – Operating," and LCO 3.8.2, "AC Sources – Shutdown."

The starting air system is required to be maintained ≥250psig to meet SR 3.3.8.5. At this pressure the system meets its design criteria because it has the capability for four diesel starts, without recharging the air start receivers, each within the 10 seconds assumed for a LOCA. At 90 psig the system has the capability for one diesel start within the 10 seconds assumed for a LOCA. The 250 psig and 90 psig limits for air start receiver pressure are analytical limits. Therefore, an appropriate allowance for instrument uncertainty must be applied when ensuring these limits are met. To allow for instrument uncertainty, administrative limits for starting air pressure if ≥ 260 psig and ≥ 100 psig are used, respectively.

(continued)

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil and the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

<u>A.1</u>

In this Condition, the requirements of SR 3.8.3.2.a are not met. Therefore, a DG will not be able to support 48 hours of continuous operation at minimum safeguards load and replenishment of the DG fuel oil storage tanks will be required in less than 48 hours following an accident. The DG associated with the DG fuel oil storage tank not within limits must be declared inoperable immediately because replenishment of the DG fuel oil storage tank requires that fuel be transported from the offsite DG fuel oil reserve by truck and the volume of fuel oil remaining in the DG fuel oil storage tank may not be sufficient to allow continuous DG operation while the fuel transfer is planned and conducted under accident conditions.

This Condition is preceded by a Note stating that Condition A is applicable only in MODES 1, 2, 3 and 4. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks when in these MODES.

(continued)

ACTIONS (continued)

B.1

In this Condition, the requirements of SR 3.8.3.2.b are not met. With less than the total required minimum fuel oil in one or more DG fuel oil storage tanks, the one or two DGs required to be operable in MODES 5 and 6 and during movement of irradiated fuel may not have sufficient fuel oil to support continuous operation while a fuel transfer from the offsite DG fuel oil reserve or from another offsite source is planned and conducted under accident conditions. Fuel oil credited to meet this requirement must be in one or more storage tanks associated with the operable DG(s) because the fuel transfer pump in each tank may depend on power from that DG.

This condition requires that all DGs be declared inoperable immediately because minimum fuel oil level requirements in SR 3.8.3.2.b is a condition of Operability of all DGs when in the specified MODES.

This Condition is preceded by a Note stating that Condition B is applicable only in MODES 5 and 6 and during the movement of irradiated fuel. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks when in these MODES.

C.1

In this Condition, the fuel oil remaining in the offsite DG fuel oil reserve is not sufficient to operate 2 of the 3 DGs at minimum safeguards load for 7 days. Therefore, all 3 DGs are declared inoperable immediately.

This Condition is preceded by a Note stating that Condition D is applicable only in MODES 1, 2, 3 and 4 because the offsite DG fuel oil reserve is required to be available only in these MODES. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required when in these MODES.

(continued)

ACTIONS (continued)

D.1

This Condition is entered as a result of a failure to meet the acceptance criteria of SR 3.8.3.3 or SR 3.8.3.4 when the DG fuel oil storage tanks or reserve storage tanks are verified to have particulate within the allowable value in Specification 5.5.12, Diesel Fuel Oil Testing Program. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7-day and 30-day Completion Times, for the onsite tanks and the reserve storage tanks, respectively, allows for further evaluation, resampling and re-analysis of the DG fuel oil.

E.1

This condition is entered as a result of a failure to meet the acceptance criteria of SR 3.8.3.3 or SR 3.8.3.4 when the DG fuel oil storage tanks or reserve storage tanks are verified to have properties (other than particulates) within the allowable values of Specification 5.5.12, Diesel Fuel Oil Testing Program. A period of 30 days is allowed to restore the properties of the fuel oil in the DG fuel oil storage tank to within the limits established by Specification 5.5.12. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combinations of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that

(continued)

ACTIONS

E.1. (continued)

the DG would still be capable of performing its intended function. A period of 60 days is allowed to restore the properties of the fuel oil stored in the affected reserve storage tank to within the limits established by Specification 5.5.12. This period provides sufficient time to perform the actions described above for the DG fuel oil storage tanks. The additional time allowed for the reserve tanks is acceptable because reserve oil is not immediately needed to support DG operation and reserve oil is available from more than one reserve tank. Reserve oil is also available from commercial suppliers in the vicinity of the plant.

F.1

With starting air receiver pressure < 250 psig, sufficient capacity for four successive DG start attempts does not exist. However, as long as the receiver pressure is ≥ 90 psig, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. The SR 3.8.3.5 limit for air start receiver pressure of 250 psig is an analytical limit. Therefore an appropriate allowance for instrument uncertainty must be applied when ensuring this limit is met. To allow for this instrument uncertainty, an administrative limit for starting air pressure of ≥ 260 psig is used. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period. Entry into Condition F is not required when air receiver pressure is less than required limits while the DG is operating following a successful start.

G.1

With a Required Action and associated Completion Time not met, or one or more DG's fuel oil or starting air subsystem not within limits for reasons other than addressed by Conditions A through F, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the offsite DG fuel oil reserve to support 2 DGs at minimum safeguards load for 7 days assuming requirements for the DG fuel oil storage tanks and day tanks are met. The 7 day duration with 2 of the 3 DGs at minimum safeguards load is sufficient to place the unit in a safe shutdown condition and to bring in replenishment fuel from a commercial source.

The 24 hour Frequency was needed because the DG fuel oil reserve is stored in fuel oil tanks that used to support the operation of gas turbine peaking units that are not under IP3 control. Specifically, the 26,826 gallons needed to support 7 days of DG operation is maintained in two 30,000 gallon tanks located in the Indian Point 1 Superheater Building and/or a 200,000 gallon tank in the Buchanan Substation. Although the volume of fuel oil required to support IP3 DG operability is designated as for the exclusive use of IP3, the fact that the oil in the storage tanks is used for purposes other than IP3 DGs and oil consumption is not under the direct control of IP3 operators warrants frequent verification that required offsite DG fuel oil reserve volume is being maintained.

SR 3.8.3.2

SR 3.8.3.2.a provides verification when in MODES 1, 2, 3, and 4, that there is an adequate inventory of fuel oil in the storage DG fuel oil tanks to support each DG's operation for at least 48 hours of operation of minimum safeguards equipment when any two of the DG fuel oil storage tanks are available and 5,365 gallons of usable fuel oil is contained in each tank.

SR 3.8.3.2.b provides verification when in MODES 5 and 6 and during movement of irradiated fuel that the minimum required fuel oil for operation in these MODES is available in one or more DG fuel oil storage tanks. The minimum required volume of fuel oil

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

takes into account the reduced DG loading required to respond to events in MODES 5 and 6 is sufficient to support the two DGs required to be operable in MODES 5 and 6 and during movement of irradiated fuel while a fuel transfer from the offsite DG fuel oil reserve or from another offsite source is planned and conducted under accident conditions.

This minimum volume required by SR 3.8.3.2.a and SR 3.8.3.2.b is the usable volume and does not include allowances for fuel not usable due to the fuel oil transfer pump cutoff switch (worst case 956 gallons for #33 tank and 915 gallons for #31 and #32 tanks) and margin (20 gallons per tank). If the installed level indicators are used to measure tank volume, an additional allowance of 50 gallons for instrument uncertainty associated with the level indicators must be included. Appropriate adjustments are required for SR 3.8.3.2.b if the required volume is found in more than one DG fuel oil storage tank.

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

SR 3.8.3.3

This surveillance verifies that the properties of new and stored fuel oil meet the acceptance criteria established by Specification 5.5.12, "Diesel Fuel Oil Testing Program." Specific sampling and testing requirements for diesel fuel oil in accordance with applicable ASTM Standards are specified in the administrative program developed to ensure Specification.

New fuel oil is sampled prior to addition to the DG fuel oil storage tanks and stored fuel oil is periodically sampled from the DG fuel oil storage tanks. Requirements and acceptance

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

criteria for fuel oil are divided into 3 parts as follows:
a) tests of the sample of new fuel sample and acceptance criteria that must be met prior to adding the new fuel to the DG fuel oil storage tanks; b) tests of the sample of new fuel that may be completed after the fuel is added to the DG fuel oil storage tanks; and, c) tests of the fuel oil stored in the DG fuel oil storage tanks. The basis for each of these tests is described below.

The tests of the sample of new fuel and acceptance criteria that must be met prior to adding the new fuel to the DG fuel oil storage tanks are a means of determining that the new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. The tests, limits, and applicable ASTM Standards needed to satisfy Specification 5.5.12 are listed in the administrative program developed to implement Specification 5.5.12.

Failure to meet any of the specified limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO because the fuel oil is not added to the storage tanks.

The tests of the sample of new fuel that may be completed after the fuel is added to the DG fuel oil storage tanks must be completed Within 31 days. The fuel oil is analyzed to establish that the other properties of the fuel oil meet the acceptance criteria of Specification 5.5.12. The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

effect on DG operation. Failure to meet the specified acceptance criteria requires entry into Condition E and restoration of the quality of the fuel oil in the DG fuel oil storage tank within the associated Completion Time and explained in the Bases for Condition E. This Surveillance ensures the availability of high quality fuel oil for the DGs.

The periodic tests of the fuel oil stored in the DG fuel oil storage tanks verify that the length of time or conditions of storage has not degraded the fuel in a manner that could impact DG OPERABILITY. Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure. Particulate concentrations must meet the acceptance criteria of Specification 5.5.12. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. Each DG fuel oil storage tank must be considered and tested separately.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.4

The IP3 offsite fuel oil reserve is maintained by the operators of IP2, in accordance with formal agreements. The IP3 offsite DG fuel oil reserve is normally stored in the same tanks used to store the IP2 offsite DG fuel oil reserve. Fuel oil properties of new and stored fuel are controlled in accordance with IP2 Technical Specifications and FSAR in order to meet requirements for the Operability of IP2 and IP3 DGs.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.4 (continued)

Required testing of the properties of new and stored fuel in the offsite DG fuel oil reserve is performed by IP2 in accordance with programs established by IP2. IP3 performs periodic verification that fuel oil stored in the offsite DG fuel oil reserve meet the requirements of Specification 5.5.12.

Failure to meet the specified acceptance criteria, whether identified by IP2 or IP3, requires entry into Condition D or E and restoration of the quality of the fuel oil in the offsite DG fuel oil reserve within the associated Completion Time and explained in the Bases for Conditions D and E.

SR 3.8.3.5

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of four engine starts without recharging. Failure of the engine to start within approximately 15 seconds indicates a malfunction at which point the overcrank relays terminate the start cycle. In this condition, sufficient starting air will still be available so that the DG can be manually started. The pressure specified in this SR is intended to reflect the lowest value at which the four starts can be accomplished.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.6

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 storage tanks once every 92 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, and contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. Unless the volume of water is sufficient that it could impact DG OPERABILITY, presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed within 7 days of performance of the Surveillance.

REFERENCES

1. FSAR, Section 8.2.
2. Regulatory Guide 1.137.
3. FSAR, Chapter 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources — Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment and preferred 120 V AC vital instrument bus power (via inverters). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also is consistent with the recommendations of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of four independent safety related DC electrical power subsystems (31, 32, 33 and 34). Each subsystem consists of one 125 VDC battery, the associated battery charger for each battery (except that battery charger 34 is not covered by this LCO), and all the associated control equipment and interconnecting cabling. In addition, battery charger 35 is an installed spare that can be used as the associated charger for any one of the batteries (Ref. 4).

The four DC electrical power subsystems (batteries and associated chargers) 31, 32, 33, and 34 feed four main distribution power panels. DC electrical power subsystems 31, 32, and 33 supply DC control power to 480 volt buses Nos. 5A, 6A, and 2A/3A, respectively. The 480 volt switchgear bus sections that supply power to the safeguards equipment also receive DC control power from its associated DC electrical power subsystem. DC electrical power subsystem 34 does not provide DC control power to any equipment assumed to function to mitigate an accident.

The DC electrical power subsystems 31, 32, 33 and 34 also provide DC electrical power to the inverters, which in turn power the AC vital instrument buses. As a result, each of the four DC electrical power subsystems supports one of the four Reactor

(continued)

BASES

BACKGROUND (continued)

Protection System (RPS) Instrumentation channels and one of the four Engineered Safety Features Actuation (ESFAS) Instrumentation channels. DC electrical power subsystems 31 and 32 each support one of the two trains of RPS Instrumentation actuation logic and one of the two trains of ESFAS Instrumentation actuation logic. Electrical distribution, including DC Sources, is described in the FSAR (Ref. 4).

During normal operation, the 125 VDC load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC load is automatically powered from the station batteries.

Each of the four station batteries is sized to carry its expected shutdown loads for a period of 2 hours without battery terminal voltage falling below 105 volts following a plant trip that includes a loss of all AC power. Major loads with their approximate operating times on each battery are listed in Reference 4. The four battery chargers have been sized to recharge discharged batteries within 15 hours while carrying the normal DC subsystem load.

Battery 34 and charger 34 were installed in 1979 (along with inverter 34) to ensure a continuous power supply to 120 V AC vital instrument bus (VIB) 34 which supports RPS and ESFAS channel III. Prior to this modification, VIB 34 was powered solely by two 480 V/120 V constant voltage transformers (CVTs) supplied by separate safeguard power trains. Although these two CVTs provide redundant safety related power supplies for VIB 34, these power sources are unavailable following a loss of offsite power until the emergency diesel generators re-power one or both of the associated safeguards power trains. Additionally, battery 34 (via the associated inverter) provides a continuous power supply for VIB 34 which decreases the potential for an inadvertent reactor trip or ESFAS actuation, especially when an instrument channel associated with a different VIB is inoperable and in trip. Note that battery charger 34 is not required by LCO 3.8.4. This is acceptable because VIB 34 can be powered by either of the two CVTs supplied by separate safeguard power trains if battery charger 34 is not available following an event.

(continued)

BASES

BACKGROUND (continued)

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution Systems — Operating," and LCO 3.8.10, "Distribution Systems — Shutdown."

Each 125 VDC battery is separately housed in a ventilated room apart from its charger and power panels. Each subsystem is separated electrically from the other subsystems to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant subsystems, such as batteries, battery chargers, or power panels.

The batteries are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The voltage limit is 2.13V per cell, which corresponds to a total minimum voltage output of ≥ 125.7V for battery 31 (consisting of 59 cells), ≥ 123.5V for battery 32 (consisting of 58 cells), and ≥ 127.8V for batteries 33 and 34 (each consisting of 60 cells).

Each DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank charged as necessary to meet the requirements of LCO 3.8.6, Battery Parameters. Each battery charger also has sufficient capacity to restore the battery from the design minimum charge to the required charged state within 15 hours while supplying normal steady state loads discussed in the FSAR, Chapter 8 (Ref. 4).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 6), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power subsystems 31, 32 and 33 provide normal and emergency DC electrical power for the DGs, and control and switching during all MODES of operation. Each of the four DC electrical power subsystems supports one of the four 120 V AC vital instrument buses via an inverter.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the DC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC power or all onsite AC power (i.e., emergency diesel generators); and

b. A worst case single failure.

The DC sources satisfy Criterion 3 of 10 CFR 50.36.

LCO

This LCO requires the OPERABILITY of the following four DC electrical power subsystems:

Battery 31 and associated Battery Charger;
Battery 32 and associated Battery Charger;
Battery 33 and associated Battery Charger; and
Battery 34.

In addition, the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the train are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any train DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

An OPERABLE DC electrical power subsystem requires the battery and respective charger to be operating and connected to the associated DC bus.

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that:

(continued)

BASES

APPLICABILITY (continued)

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

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

The DC electrical power requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.5, "DC Sources — Shutdown."

ACTIONS

A.1

Condition A is entered when battery No. 34 is not OPERABLE. The only safety related load supported by DC subsystem 34 is 120 V AC vital instrument bus 34 which is supplied via inverter 34. Therefore, the Required Actions for inverter 34 not OPERABLE specified in LCO 3.8.7, Inverters-Operating, are appropriate when battery No. 34 is not OPERABLE. Additionally, ITS 3.8.9 (and ITS Section 3.3) ensure that 120 V AC vital instrument bus 34 is energized when required. The 2 hour Completion Time is consistent with the completion time for an inoperable battery and/or charger in any of the other three DC electrical power subsystems.

B.1

Condition B is entered when DC subsystem 31, 32 or 33 (battery and/or associated charger) is not Operable. Loss of DC subsystem 34 (Condition A) differs from the loss of DC subsystem 31, 32 or 33 (Condition B) because Condition B could result in the loss of DC control power to 480 volt bus No. 5A, 6A, or 2A/3A, respectively, and the associated emergency diesel generator. Therefore, this Condition represents a significant degradation of the ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation.

(continued)

BASES

ACTIONS

B.1 (continued)

It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential loss of additional DC subsystems.

If one of the required DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger, or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure would, however, result in the loss of another 125 VDC electrical power subsystems with attendant loss of ESF functions, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

C.1 and C.2

If the inoperable DC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 11). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 11, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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 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 for the batteries helps to ensure the effectiveness of the charging system and 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 (or a battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The 31 day Frequency is consistent with manufacturer recommendations and IEEE-450 (Ref.8).

SR 3.8.4.2

This SR requires that each battery charger be capable of supplying the voltage and current necessary to recharge partially discharged batteries (two hour discharge at a rate that does not cause battery terminal voltage to fall below 105 volts). These requirements are consistent with the output rating of the chargers (Ref. 4). Therefore, this SR can be satisfied by operating each charger at the design voltage and current for a minimum of 2 hours. According to Regulatory Guide 1.32 (Ref. 9), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.2 (continued)

the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

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.

This Surveillance is required to be performed during MODES 5 and 6 since it would require the DC electrical power subsystem to be inoperable during performance of the test.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance: as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown or startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.3

A battery service test is a special test of battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length should correspond to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed during refueling operations or at some other outage.

A modified performance discharge test may be performed in lieu of a service test.

The modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified performance discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.4

A battery performance discharge test is a test of constant current capacity of a battery, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

A battery modified performance discharge test is described in the Bases for SR 3.8.4.3. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.4; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.4 while satisfying the requirements of SR 3.8.4.3 at the same time.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 8) and IEEE-485 (Ref. 5). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 8), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer's rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 8).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

SR 3.8.4.5

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

(continued)

BASES

REFERENCES

1. 10 CFR 50, Appendix A.

2. Regulatory Guide 1.6, March 10, 1971.

3. IEEE-308-1978.

4. FSAR, Chapter 8.

5. IEEE-485-1983, June 1983.

6. FSAR, Chapter 14.

7. Regulatory Guide 1.93, December 1974.

8. IEEE-450-1995.

9. Regulatory Guide 1.32, February 1977.

10. Regulatory Guide 1.129, December 1974.

11. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources – Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources – Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapter 14 (Ref. 1), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

The DC sources satisfy Criterion 3 of 10 CFR 50.36.

(continued)

BASES (continued)

LCO

The four DC electrical power subsystems, each subsystem consisting of one battery, one battery charger (except for battery charger 34 which is not covered by this LCO), and the corresponding control equipment and interconnecting cabling within the safeguards power train, are required to be OPERABLE to support required safeguards power trains of the distribution systems required OPERABLE by LCO 3.8.10, "Distribution Systems – Shutdown." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

DC subsystems 31 and 32 may be cross connected and powered by battery 31 or 32 and both DC subsystems remain OPERABLE (Ref.2). Similarly, DC subsystems 33 and 34 may be cross connected and powered by battery 33 or 34. However, only one pair of subsystems at a time may be cross connected. Cross connecting DC subsystems in Modes 5 and 6 and during movement of irradiated fuel is acceptable because there is no requirement for redundancy or separation between DC busses when the plant is in this condition. Both DC subsystems in the cross connected pair remain OPERABLE even when powered by one battery because the capacity of one battery is adequate to carry the loads on both busses when the plant is in this condition.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

(continued)

BASES

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3 and A.2.4

If any DC electrical subsystem required by LCO 3.8.10 becomes inoperable, the remaining DC power available may be capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features inoperable with the associated DC power source(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCO ACTIONS. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions). The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory, provided the required SDM is maintained.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.4. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. FSAR, Chapter 14.
2. FSAR, Chapter 8.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND

This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources – Operating," and LCO 3.8.5, "DC Sources – Shutdown."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining at least one train of DC sources OPERABLE during accident conditions, in the event of:

a. An assumed loss of all offsite AC power or all onsite AC power; and

b. A worst case single failure.

Battery cell parameters satisfy the Criterion 3 of 10 CFR 50.36.

LCO

Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA.

(continued)

BASES

LCO (continued)	Electrolyte limits are conservatively established, allowing continued DC electrical system function even with Category A and B limits not met.
APPLICABILITY	The battery cell parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery electrolyte is only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.
ACTIONS	The ACTIONS Table is modified by a Note which indicates that separate Condition entry is allowed for each battery. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DC subsystem. Complying with the Required Actions for one inoperable DC subsystem may allow for continued operation, and subsequent inoperable DC subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

<u>A.1, A.2 and A.3</u>

With one or more cells in one or more batteries not within limits (i.e., Category A limits not met, Category B limits not met, or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1 in the accompanying LCO, the battery is degraded but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met and operation is permitted for a limited period.

The pilot cell electrolyte level and float voltage are required to be verified to meet the Category C limits within 1 hour (Required Action A.1). This check will provide a quick indication of the status of the remainder of the battery cells.

(continued)

BASES

ACTIONS

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

One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cells. One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A or B limits. This periodic verification is more frequent than the normal Frequency of pilot cell Surveillances because of the degraded condition of the battery.

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. With the consideration that, while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable prior to declaring the battery inoperable.

B.1

With one or more batteries with one or more battery cell parameters outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as not completing the

(continued)

BASES

ACTIONS

B.1 (continued)

Required Actions of Condition A within the required Completion Time or average electrolyte temperature of representative cells outside the limits of SR 3.8.6.3 are also cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 2), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells.

SR 3.8.6.2

The quarterly inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 2) which recommends augmentation of the battery inspections conducted in SR 3.8.6.1 at least once per quarter by checking the level, voltage and specific gravity of each cell, and the temperature of pilot cells.

Measuring and recording the amount of water added is a trending method for those cells found with electrolyte below minimum level.

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells (i.e., every fifth cell) is within specified limits, is consistent with a recommendation of IEEE-450 (Ref. 2), that states that the temperature of electrolytes in representative cells should be determined on a quarterly basis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.3 (continued)

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturer recommendations.

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturer recommendations and are consistent with the guidance in IEEE-450 (Ref. 2), with the extra ¼ inch allowance above the high water level indication for operating margin to account for temperatures and charge effects. In addition to this allowance, footnote a to Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 2) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on the recommendations of IEEE-450 (Ref. 2), which states that prolonged operation of cells < 2.13 V can reduce the life expectancy of cells.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category A limit specified for specific gravity for each pilot cell is ≥ 1.205 (0.010 below the manufacturer fully charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 2), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings are corrected for actual electrolyte temperature as long as level is maintained within the required range. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ 1.195 (0.020 below the manufacturer fully charged, nominal specific gravity) with the average of all connected cells > 1.205 (0.010 below the manufacturer fully charged, nominal specific gravity). These values are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell will not mask overall degradation of the battery.

Category C defines the limits for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

When any battery parameter is outside the Category C limits, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

The Category C limits specified for electrolyte level (above the top of the plates and not overflowing) ensure that the plates suffer no physical damage and maintain adequate electron transfer capability.

The Category C limits for float voltage is based on IEEE-450 (Ref. 2), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit of average specific gravity ≥ 1.195 is based on manufacturer recommendations (0.020 below the manufacturer recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

The footnotes to Table 3.8.6-1 are applicable to Category A, B and C specific gravity. Footnote (b) to Table 3.8.6-1 requires the above-mentioned correction for electrolyte temperature.

Footnote (c) to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for up to 7 days following a battery recharge.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref.2). Within 7 days, each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements may be made in less than 7 days.

REFERENCES

1. FSAR, Chapter 14.

2. IEEE-450-1995.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters — Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the 120 V AC vital instrument buses because of the stability and reliability they achieve. The function of the inverter is to provide AC electrical power to the vital instrument buses.

There are four 120 volt AC vital instrument buses (VIBs), Nos. 31, 32, 33 and 34. The preferred power supplies to these buses are static inverters, Nos. 31, 32, 33 and 34, which are in turn supplied from separate 125 volt DC buses, Nos. 31, 32, 33 and 34. Each of the four 125 volt DC buses is powered by a battery and associated battery charger.

Inverters 31, 32, and 33 each have an associated backup 480 V/120 V constant voltage transformer (CVT). Each of these inverters has a manual bypass switch that causes the associated VIB to receive AC power from plant AC sources via the backup CVT instead of the DC powered inverter. Inverters 31, 32, and 33 will transfer to the backup power supply (i.e., the associated CVT) automatically in the event of an inverter failure. However, this auto-transfer feature is not credited in the safety analysis. The backup CVTs for inverters 31, 32, and 33 are supplied from non-safety related buses that are stripped and not automatically re-connected following a safety injection (SI) signal or a loss of offsite power (LOOP). Therefore, operator action is required to re-energize VIBs 31, 32, or 33 following an SI or LOOP if the associated inverter is being bypassed or fails during the event. Additionally, the potential exists that the bus powering the backup CVT may not be available following an event.

Inverter 34 has two associated backup 480 V/120 V constant voltage transformers (CVTs). The CVTs associated with inverter 34 are powered from separate safeguards power trains using buses that are automatically re-energized following an SI or LOOP. One CVT is powered from MCC 36C and the other is powered from MCC 36B. Inverter 34 can be manually bypassed such that either of the associated CVTs can be used to power VIB 34. Inverter 34 will automatically transfer to the backup CVT powered from MCC 36C in the event of an inverter failure. However, this auto-transfer feature is not credited in the safety analyses. Manual operator action is needed to transfer to the backup CVT powered from MCC 36B.

(continued)

BASES

BACKGROUND (continued)

Using a separate battery and inverter to power each VIB ensures a continuous source of power for the instrumentation and controls of the engineered safety features (ESF) systems and the reactor protection system (RPS) during postulated events including the loss of offsite power. This is consistent with requirements described in Generic Letter 91-011 (Ref. 1). Continuity of power to the VIBs is assured because each of the four station batteries is sized to carry its expected shutdown loads for a period of 2 hours (Ref. 2). Additionally, four battery chargers have been sized to recharge these batteries while carrying the normal DC subsystem load (Ref. 2).

Note that battery charger 34 is not required by LCO 3.8.4. This is acceptable because VIB 34 can be powered by either of the two CVTs supplied by separate safeguard power trains if battery charger 34 is not available following an event. Specific details on inverters and their operating characteristics are found in the FSAR, Chapter 8 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 3), assumes Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining required 120 V AC vital instrument buses OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC electrical power or all onsite AC electrical power; and

b. A worst case single failure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The 2 CVTs capable of supplying VIB 34 are needed to ensure the availability of power to VIB 34 following the depletion of battery 34. Although battery charger 34 would normally be used to supply VIB 34 via inverter 34, battery charger 34 is not safety related and may not be available after a design basis event.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36.

LCO

The inverters (and CVTs associated with VIB 34) ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required inverters (and CVTs associated with VIB 34) OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The four inverters ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 480 V safety buses are de-energized.

Operable inverters require the associated 120 V AC vital instrument bus to be powered by the inverter with output voltage and frequency within tolerances, and power input to the inverter from a 125 VDC station battery.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, "Inverters — Shutdown."

(continued)

BASES

ACTIONS

With an inverter inoperable, its associated VIB becomes inoperable until it is re-energized from its associated backup CVT. For this reason a Note to the Actions requires entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating." This ensures that the vital bus is re-energized within 2 hours.

A.1

With one of the two CVTs capable of supplying VIB 34 not OPERABLE, VIB 34 will be powered from battery 34 via inverter 34 for a minimum of 2 hours following the initiation of any event. After battery 34 is depleted, the second CVT capable of powering VIB 34 will maintain power to VIB 34 even if non-safety related battery charger 34 is not available. A 30 day Completion Time to restore both CVTs to OPERABLE is needed because a failure of the safeguards power train supporting the remaining CVT would result in the loss of two VIBs (i.e, VIB 34 and the VIB associated with the failed safeguards power train) but only after the associated batteries are depleted. A 30 day Completion Time to restore both CVTs to OPERABLE is acceptable because of the low probability of an accident in conjunction with the loss of a specific safeguards power train.

B.1

With both of the CVTs capable of supplying VIB 34 not OPERABLE, VIB 34 will be powered from battery 34 via inverter 34 for a minimum of 2 hours following the initiation of any event. After battery 34 is depleted, inverter 34 may not be available to power VIB 34 because battery charger 34 is not safety related and is powered from a non-safety related bus. Therefore, at least one CVT must be restored within 7 days.

A 7 day Completion Time to restore at least one of the two CVTs to OPERABLE is needed and is acceptable because of the following: VIB 34 will be powered from battery 34 via inverter 34 for a minimum of 2 hours; non-safety related battery charger 34 may be available following an event; and, the low probability of an event during this 7 day period.

(continued)

BASES

ACTIONS

C.1 and C.2

With an inverter inoperable, its associated VIB must be powered from its associated backup CVT. However, the backup CVTs for inverters 31, 32, and 33 are supplied from non-safety related buses that are stripped and not automatically re-connected following a SI signal or a LOOP. Both backup CVTs for inverter 34 are powered from safety related buses that may be de-energized until the associated safeguards power train is energized (i.e., diesel generator starts). Therefore, a VIB powered from a backup CVT when the associated inverter is inoperable will be and could remain de-energized following a SI signal or a LOOP.

If a VIB will be de-energized as a result of SI signal or LOOP, a loss of safety function could exist for any VIB powered function that requires power to perform the required safety function (e.g., automatic actuation of core spray, Regulatory Guide 1.97 instrumentation, etc.) if the redundant required feature is inoperable. Therefore, Required Action C.1 requires declaring required feature(s) supported by associated inverter inoperable when its required redundant feature(s) is inoperable. As specified in the associated Note, this requirement only applies to feature(s) that require power to perform the required safety function. The 2 hour Completion Time is consistent with LCO 3.8.9, AC Distribution System - Operating, requirements for an inoperable VIB.

With an inverter inoperable and its associated VIB powered from its associated backup CVT, there is increased potential for inadvertent actuation for ESFAS or RPS functions, especially if redundant channels are inoperable and in the tripped condition. This is because these de-energize to actuate functions are relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the VIBs is the preferred source for powering instrumentation trip setpoint devices. Therefore, only one inverter may be inoperable at one time and an inoperable inverter must be restored to OPERABLE within 7 days. The 7 day Completion Time is needed because it ensures that the VIBs are powered from the uninterruptible inverter source. The 7 day Completion Time is acceptable because Required Action C.1 ensures that an inoperable inverter does not result in a loss of any safety function. The 7 day Completion Time is consistent with commitments made in response to Generic Letter 91-011 (Ref. 1).

(continued)

BASES

ACTIONS

D.1 and D.2

If the inoperable devices or components cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which overall plant risk is reduced.

To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action D.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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 plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation of the RPS and ESFAS connected to the AC vital 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.

SR 3.8.7.2

This Surveillance verifies that the power supply to VIB 34 can be manually transferred from the inverter to each of the required CVTs. This SR ensures that power to VIB 34 can be maintained after the depletion of battery 34. The 24 month Frequency takes into account that either of the CVTs is capable of performing this safety function and the demonstrated reliability of this equipment.

REFERENCES

1. Generic Letter 91-011, Resolution of Generic Issues 48, "LCOs for Class 1E Vital Instrument Buses," and 49, "Interlocks and LCOS for Class 1E Tie Breakers" pursuant to 10 CFR 50.54(f).

2. FSAR, Chapter 8.

3. FSAR, Chapter 14.

4. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters – Shutdown

BASES

BACKGROUND

A description of the inverters is provided in the Bases for LCO 3.8.7, "Inverters – Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature systems, including inverters that supply required 120 V AC vital instrument buses, are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protective System and Engineered Safety Features Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of one inverter to each VIB bus during MODES 5 and 6 and when moving irradiated fuel ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is available to mitigate events postulated during shutdown, such as a fuel handling accident.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The inverters were previously identified as part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36.

LCO

The inverters ensure the availability of electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. The battery powered inverters provide uninterruptible supply of AC electrical power to the VIBs even if the 480 V safety buses are de-energized. OPERABILITY of the inverters requires that the VIB be powered by the inverter. This ensures the availability of sufficient inverter power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

This LCO does not require OPERABILITY of the constant voltage transformers (CVTs) capable of supplying VIB 34 even if inverter 34 is required to be OPERABLE. This is acceptable because VIB 34 will be powered from battery 34 via inverter 34 for a minimum of 2 hours and electrical buses may be cross connected as needed to support inverter 34 prior to the depletion of battery 34.

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

(continued)

BASES

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3 and A.2.4

If more than one VIB is required by LCO 3.8.10, "Distribution Systems — Shutdown," the remaining OPERABLE Inverters may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for positive reactivity additions. By the allowance of the option to declare required features inoperable with the associated inverter(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs' Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions). The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory, provided the required SDM is maintained.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention.

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3 and A.2.4 (continued)

The restoration of the required inverters should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power or powered from a constant voltage source transformer.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and VIBs 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 VIBs. 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.

REFERENCES

1. FSAR, Chapter 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems — Operating

BASES

BACKGROUND

The onsite AC, DC, and 120 V AC vital instrument bus VIB electrical power distribution systems are divided into three safeguards power trains (5A, 2A/3A and 6A) consisting of four 480 VAC safeguards buses and associated AC electrical power distribution subsystems, four 125 VDC bus subsystems, and four VIBs.

The safeguards subsystems are arranged in three trains such that any two trains are capable of meeting minimum requirements for accident mitigation or safe shutdown. The three safeguards subsystems consist of 480 volt bus 5A (associated with DG 33), 480 volt bus 6A (associated with DG 32), and 480 volt buses 2A and 3A (associated with DG 31). Buses 2A and 3A are considered a single safeguards bus. The electrical subsystems are identified in Table B 3.8.9-1.

The AC electrical power subsystem for each train consists of an Engineered Safety Feature (ESF) 480 V bus and motor control centers. Each 480 V bus has at least one offsite source of power as well as a dedicated onsite diesel generator (DG) source. Each of the four 480 V volt buses can receive offsite power from either the normal (138 kV) or alternate (13.8 kV) offsite source. The normal offsite power source uses either of the two 138 kilovolt (kV) ties from the Buchanan substation. The alternate offsite power source uses either of the two 13.8 kV ties from the Buchanan substation. There is no automatic transfer from the normal to the alternate source of offsite power.

Offsite power to 480 V buses 5A and 6A is supplied from 6.9 kV buses 5 and 6, respectively, which in turn receive power from either 138 kV offsite feeder via the Station Auxiliary Transformer (SAT). Alternately, 6.9 kV buses 5 and 6 can be supplied from either of the two 13.8 kV ties via an auto-transformer associated with the 13.8 kV feeder being used.

(continued)

BASES

BACKGROUND (continued)

When the plant is at power, 480 V buses 2A and 3A are normally powered from the Main Generator via the Unit Auxiliary Transformer (UAT) and the 6.9 kV buses 2 and 3 via SSTs 2 and 3. When the plant is not operating, buses 2A and 3A are supplied from 6.9 kV buses 5 and 6, respectively, via tie breakers. Following a unit trip, power to 480 V buses 2A and 3A is maintained by a fast transfer that connects buses 2A and 3A to power supplied from offsite to 6.9 kV buses 5 and 6. If the 138 kV system is not available, either of the two independent 13.8 kV feeders can be connected to the 6.9 kV buses through associated 20 MVA 13.8 KV/6.9 KV auto-transformers. When the 13.8 kV power source is used to feed 6.9 kV buses 5 and 6 and the main generator is used to feed 6.9 kV buses 1, 2, 3 and 4, automatic transfer of the 6.9 KV buses 1, 2, 3 and 4 to the 13.8 kV source following a unit trip must be prohibited to prevent overloading of the 13.8 kV auto-transformer. Therefore, a unit trip when a 13.8 kV power source is used to feed 6.9 kV buses 5 and 6 will result in 480 V busses 2A and 3A being de-energized and subsequently being powered from DG 31.

Each of the three 480 V safeguards subsystems receives DC control power from its associated battery charger and battery source. Battery No. 31 supplies DC control power to safeguards power train 5A including DG 33. Battery No. 32 supplies DC control power to safeguards power train 6A including DG 32. Battery No. 33 supplies DC control power to safeguards power train 2A/3A including DG 31. Batteries 31 and 32 also supply ESFAS and RPS trains A and B, respectively. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources — Operating," and the Bases for LCO 3.8.4, "DC Sources — Operating."

The AC electrical power distribution system for each train includes the safety related motor control centers shown in Table B 3.8.9-1.

There are four 120 volt vital AC instrument buses (VIBs), each consisting of two interconnected buses. The four VIBs are powered by static inverters that are powered from the four separate 125 volt DC buses.

(continued)

BASES

BACKGROUND (continued)

Inverters 31, 32, and 33 each have an associated backup 480 V/120 V constant voltage transformer (CVT). Each of these inverters has a manual bypass switch that causes the associated VIB to receive AC power from plant AC sources via the backup CVT instead of the DC powered inverter. Inverters 31, 32, and 33 will transfer to the backup power supply (i.e., the associated CVT) automatically in the event of an inverter failure. However, the backup CVTs for inverters 31, 32, and 33 are supplied from non-safety related buses that are stripped and not automatically re-connected following a safety injection (SI) signal or a loss of offsite power (LOOP). Therefore, operator action is required to re-energize VIBs 31, 32, or 33 following an SI or LOOP if the associated inverter is being bypassed or fails during the event. Additionally, the potential exists that the bus powering the backup CVT may not be available following an event.

Inverter 34 has two associated backup 480 V/120 V constant voltage transformers (CVTs). The CVTs associated with inverter 34 are powered from separate safeguards power trains using buses that are automatically re-energized following an SI or LOOP. Inverter 34 can be manually bypassed such that either of the associated CVTs can be used to power VIB 34. Inverter 34 will automatically transfer to a backup power supply (i.e., the associated CVT powered from MCC 36C) in the event of an inverter failure. Manual operator action is needed to transfer to the other backup CVT that is powered from MCC 36B.

The 125 volt DC system is divided into four buses with one battery and battery charger (supplied from the 480 volt system) serving each. The battery chargers supply the normal DC loads as well as maintaining proper charges on the batteries. The DC system is redundant from battery source to actuation devices which are powered from the batteries. Four batteries feed four DC power panels, which in turn feed major loads, such as instrument bus inverters and switchgear control circuits. DC power panels 31 and 32 feed DC distribution panels, which in turn feed relaying and instrumentation loads. Continuity of power to the VIBs is assured because each of the four station batteries is sized to carry its expected shutdown loads for a period of 2 hours.

(continued)

BASES

BACKGROUND (continued)

Additionally, four battery chargers have been sized to recharge these batteries while carrying the normal DC subsystem load (Ref. 2).

Note that battery charger 34 is not required by LCO 3.8.4, DC Sources - Operating. This is acceptable because VIB 34 can be powered by either of the two CVTs supplied by separate safeguard power trains if battery charger 34 is not available following an event. The 2 CVTs capable of supplying VIB 34 are needed to ensure the availability of power to VIB 34 following the depletion of battery 34. Although battery charger 34 would normally be used to supply VIB 34 via inverter 34, battery charger 34 is not safety related and may not be available after a design basis event.

The list of all required distribution buses is presented in Table B 3.8.9-1.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 1), assume ESF systems are OPERABLE. The AC, DC, and AC vital instrument bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC, DC, and VIB electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining power distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC electrical power; and

b. A worst case single failure.

The distribution systems satisfy Criterion 3 of 10 CFR 50.36.

(continued)

BASES

LCO

The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and VIB electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The AC, DC, and VIB electrical power distribution subsystems are required to be OPERABLE.

Maintaining the AC, DC, and VIB electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

OPERABLE AC electrical power distribution subsystems require the associated buses and safety related motor control centers to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital instrument bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated inverter via inverted DC voltage or constant voltage transformer.

In addition, tie breakers between redundant safety related AC, DC, and VIB power distribution subsystems must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, that could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the affected redundant electrical power distribution subsystems are considered inoperable. This applies to the onsite, safety related redundant electrical power distribution subsystems. It does not, however, preclude redundant 480 V buses from being powered from the same offsite circuit.

(continued)

BASES

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems — Shutdown."

ACTIONS

A.1

With one or more required AC buses or motor control centers (except VIBs) in one train inoperable, the remaining AC electrical power distribution subsystems in the other trains are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure and that redundant required features are OPERABLE. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses and motor control centers must be restored to OPERABLE status within 8 hours.

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this Condition, the unit is more vulnerable to a loss of the minimum required AC power. It is, therefore, imperative that the

(continued)

BASES

ACTIONS

A.1 (continued)

unit operator's attention be focused on minimizing the potential for loss of power to the remaining trains by stabilizing the unit, and on restoring power to the affected train. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

The second Completion Time for Required Action A.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 A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 2 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

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

(continued)

BASES

ACTIONS (continued)

B.1

With one VIB inoperable, the remaining OPERABLE AC vital instrument buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition assuming redundant required features are inoperable. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital instrument bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated inverter via inverted DC, or constant voltage transformer.

Condition B represents one VIB without power; potentially both the DC source and the associated AC source are nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of minimum required non-interruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining vital instrument buses and restoring power to the affected vital instrument bus.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate vital instrument bus AC power. Taking exception to LCO 3.0.2 for components without adequate vital instrument bus AC power, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate VIB AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

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

(continued)

BASES

ACTIONS

B.1 (continued)

The 2 hour Completion Time takes into account the importance to safety of restoring the VIB to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B 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 could lead to a total of 10 hours, since initial failure of the LCO, to restore the VIB distribution system. At this time, an AC train could again become inoperable, and VIB distribution 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 will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

C.1

With one DC bus inoperable, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure and that redundant required features are OPERABLE. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported.

(continued)

ACTIONS

C.1 (continued)

Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition C represents one train without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning. In this situation, the unit is significantly more vulnerable to a loss of minimum required DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining trains and restoring power to the affected train.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; 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. 2). 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

(continued)

BASES

ACTIONS

C.1 (continued)

instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution 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 will result 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 to fail to meet the LCO indefinitely.

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 3). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 3, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action D.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

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 plant systems.

E.1

With one or more trains with inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other vital functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

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

REFERENCES

1. FSAR, Chapter 14.

2. Regulatory Guide 1.93, December 1974.

3. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

Table B 3.8.9-1 (page 1 of 2)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	Safeguards Power Train 5A (DG 33)	Safeguards Power Train 2A/3A (DG 31)	Safeguards Power Train 6A (DG 32)	
AC Electrical Power Distribution subsystems	480 V	bus 5A[1] MCC 36A MCC 36E[5] MCC 311[6]	bus 2A[1] bus 3A[1] MCC 36C	bus 6A[1] MCC 36B MCC 36D[5]	
AC vital[(4)] instrument buses (VIBs)	120 V	bus 31 bus 31A	bus 33 bus 33A	bus 32 bus 32A	bus 34[3] bus 34A[3]
DC buses	125 V	bus 31[2]	bus 33[2]	bus 32[2]	bus 34[2]

NOTES:

(1) Tie breakers must be open between buses 5A and 2A and between buses 3A and 6A.

(2) Tie breakers between DC buses must be open.

(3) The AC Power supply to the VIB 34 and VIB 34A is supplied from MCC 36B or MCC 36C as described in the Bases for LCO 3.8.7, Inverters - Operating.

(4) Each bus pair (e.g., 31 and 31A) constitutes a single vital instrument bus.

(5) MCC 36D and MCC 36E are only required to meet LCO 3.8.9 when the associated DG is OPERABLE or when the MCC powers 35 Battery Charger to meet LCO 3.8.4. This is acceptable since these are the only components powered from these MCCs that support Technical Specification specified functions.

(continued)

Table B 3.8.9-1 (page 2 of 2)
AC and DC Electrical Power Distribution Systems

NOTES: (continued)

Additionally, note that power from MCC 36D also supports heat detectors for the release of Fire Door FDR-30-CB, electrical thermal links for the CO2 dampers, and interlocks for the exhaust fans in control building areas of the Cable Spreading Room, Battery Rooms, and Switchgear Room. These fire protection components are inoperable upon loss of power from MCC 36D (refer to Technical Requirements Manual 3.7.A.3, 3.7.A.4, and 3.7.A.7).

(6) MCC 311 is only required to meet LCO 3.8.9 when the Main Feedwater Inlet Isolation Valves are OPERABLE since these are the only components powered from this MCC that support Technical Specification specified functions.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems – Shutdown

BASES

BACKGROUND

A description of the AC, DC, and 120 V AC vital instrument bus (VIB) electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems – Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and VIB electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC, DC, and VIB electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC, DC, and VIB electrical power distribution subsystems during MODES 5 and 6, and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36.

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of required systems, equipment, and components – all specifically addressed in each LCO and implicitly required via the definition of OPERABILITY.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the unit in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

(continued)

BASES

APPLICABILITY (continued)

The AC, DC, and VIB electrical power distribution subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4 and A.2.5

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions).

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit safety systems.

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal (RHR) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR inoperable, which results in taking the appropriate RHR actions.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention.

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4 and A.2.5 (continued)

The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the AC, DC, and VIB electrical power distribution subsystems are functioning properly, with all the buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the capability of the electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter 14.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of the Reactor Coolant System (RCS) and the refueling cavity (which includes the refueling canal) during refueling ensures that the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the COLR. Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $k_{eff} \leq 0.95$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

GDC 26 of 10 CFR 50, Appendix A, requires that two independent reactivity control systems of different design principles be provided (Ref. 1). One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical and Volume Control System (CVCS) is the system capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized and the vessel head is unbolted, the head is slowly removed to form the refueling cavity. The refueling canal and the refueling cavity are then flooded with borated water from the refueling water storage tank.

(continued)

BASES

BACKGROUND (continued)

The pumping action of the RHR System in the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the refueling canal. The RHR System is in operation during refueling (see LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level") to provide forced circulation in the RCS and assist in maintaining the boron concentrations in the RCS and the refueling cavity above the COLR limit.

APPLICABLE SAFETY ANALYSES

During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis and is conservative for MODE 6. The boron concentration limit specified in the COLR is based on the core reactivity at the beginning of each fuel cycle (the end of refueling) and includes an uncertainty allowance.

The required boron concentration and the plant refueling procedures, that include use of two independent checks to verify correct fuel assembly and location, ensure that the k_{eff} of the core will remain $\leq$ 0.95 during the refueling operation. Hence, at least a 5% $\Delta k/k$ margin of safety is established during refueling.

During refueling, the water volume in the spent fuel pit, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes.

The limiting boron dilution accident analyzed occurs in MODE 5 (Ref. 2). A detailed discussion of this event is provided in Bases for LCO 3.1.1, "SHUTDOWN MARGIN (SDM)."

The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36.

(continued)

BASES

LCO

The LCO requires that a minimum boron concentration be maintained in all filled portions of the RCS and the refueling cavity (which includes the refueling canal) while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} of ≤ 0.95 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.

APPLICABILITY

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a $k_{eff} \leq 0.95$. Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)" ensures that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical.

ACTIONS

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant volume in the RCS or the refueling cavity is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position.

A.3

In addition to immediately suspending CORE ALTERATIONS or positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible.

(continued)

BASES

ACTIONS

A.3 (continued)

In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures that the coolant boron concentration in the RCS and the refueling cavity is within the COLR limits. For sampling purposes, the refueling cavity and canal are considered a single volume. The boron concentration of the coolant in each volume is determined periodically by chemical analysis.

A minimum Frequency of once every 72 hours is a reasonable amount of time to verify the boron concentration of representative samples. The Frequency is based on operating experience, which has shown 72 hours to be adequate.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Chapter 14.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. Two installed source range neutron flux monitors (N-31 and N-32) are part of the Nuclear Instrumentation System (NIS). Additionally, the full range Excore Neutron Flux Detection System, which was installed to satisfy Regulatory Guide 1.97 requirements, includes two channels (N-38 and N-39) capable of monitoring the source range. The full range Excore Neutron Flux Detection System provides indication of subcritical neutron flux in the Control Room using the Qualified Safety Parameters Display System (QSPDS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core.

The NIS installed source range neutron flux monitors are BF3 detectors operating in the proportional region of the gas filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The two source range NIS detectors sense thermal neutrons in the range from 1×10^{-1} to 5×10^{4} neutrons per square cm per second. In addition to count rate indication in the Control Room, this instrumentation annunciates a local horn and an alarm and light in the Control Room if the count rate increases above a preset level.

The full range Excore Neutron Flux Detection System uses high-sensitivity fission chambers sensing thermal neutrons in the range from 10^{-2} to 10^{10} neutrons per square cm per second. In addition to count rate indication from the QSPDS, this instrumentation is capable of supplying audible indication of the count rate in the control room.

The core subcritical neutron flux is continuously monitored by two source range neutron monitors which provide warning of any approach to criticality during refueling operations to alert operators to a potential boron dilution event. The operators are alerted to significant changes in the subcritical neutron flux by either the alarm or by monitoring the audible neutron count rate.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Two OPERABLE source range neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity such as with a boron dilution accident (Ref. 2) or an improperly loaded fuel assembly. The audible count rate from a source range neutron flux monitor provides prompt and definite indication of any boron dilution. The count rate increase is proportional to the subcritical multiplication factor and allows operators to promptly recognize the initiation of a boron dilution event. Prompt recognition of the initiation of a boron dilution event is consistent with the assumptions of the safety analysis and is necessary to assure sufficient time is available for isolation of the primary water makeup source before SHUTDOWN MARGIN is lost (Ref. 2).

The source range neutron flux monitors satisfy Criterion 3 of 10 CFR 50.36.

LCO

This LCO requires that two source range neutron flux monitors be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. To be OPERABLE, each source range monitor must provide visual indication in the Control Room. In addition, each source range channel must provide either an alarm at a preset neutron flux level or continuous audible signal in the Control Room.

APPLICABILITY

In MODE 6, the source range neutron flux monitors must be OPERABLE to determine changes in core reactivity. There are no other direct means available to check core reactivity levels. In MODES 2, 3, 4, and 5, these same installed source range detectors and circuitry may also be required to be OPERABLE by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

With only one source range neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and positive reactivity additions must be suspended immediately. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

B.1

With no source range neutron flux monitor OPERABLE, action to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, action shall be continued until a source range neutron flux monitor is restored to OPERABLE status.

B.2

With no source range neutron flux monitor OPERABLE, there are no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be made, the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion Time of once per 12 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration and ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

SR 3.9.2.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.1.

SR 3.9.2.2

SR 3.9.2.2 is the performance of a CHANNEL CALIBRATION every 24 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the source range neutron flux monitors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Section 14.1.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Containment Penetrations

BASES

BACKGROUND

During movement of recently irradiated fuel assemblies within containment, a release of fission product radioactivity within containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are closed, except for the OPERABLE Purge System Penetration. Since there is no potential for containment pressurization, the Appendix J leakage criteria and tests are not required.

The containment serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10 CFR 50.67, Accident Source Term. Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. During movement of recently irradiated fuel assemblies within containment, the equipment hatch must be held in place by at least four bolts. Good engineering practice dictates that the bolts required by this LCO be approximately equally spaced.

In lieu of maintaining the equipment hatch in place for containment closure, a temporary closure device may be used to maintain containment closure during movement of recently irradiated fuel

(continued)

BASES

BACKGROUND (continued)

assemblies within containment. The temporary closure device may provide penetrations for temporary services or personnel access. The temporary closure device will be designed to withstand a seismic event and designed to withstand a pressure which ensures containment closure during refueling operations. The closure device will provide the same level of protection as that of the equipment hatch for the fuel handling accident involving handling recently irradiated fuel by restricting direct air flow from the containment to the environment.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 unit operation in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During movement of recently irradiated fuel assemblies within containment, containment closure is required; therefore, the door interlock mechanism may remain disabled, but one air lock door must always remain capable of being closed.

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted to within regulatory limits.

The Containment Purge System consists of the 36-inch containment purge supply and exhaust ducts. The supply system includes roughing filters, heating coils, fan and a containment penetration with two butterfly valves for isolation. The exhaust system includes a containment penetration with two butterfly valves for isolation and can be aligned to discharge to the atmosphere through the plant vent either directly or through the Containment Purge Filter System (i.e., a filter bank with roughing, HEPA and charcoal filters).

The Containment Purge System must be isolated when in Modes 1, 2, 3 or 4 in accordance with requirements established in LCO 3.6.3, Containment Isolation Valves. In Modes 5 and 6, the Containment Purge System may be used for containment ventilation. When open, the Containment Purge System isolation valves are capable of closing in response to the detection of high radiation levels in accordance with requirements established in LCO 3.3.6, Containment Purge and Pressure Relief Isolation Instrumentation (Ref. 1).

(continued)

BASES

BACKGROUND (continued)

The Containment Pressure Relief Line (i.e., Containment Vent) consists of a single 10-inch containment vent line that is used to handle normal pressure changes in the Containment when in Modes 1, 2, 3 and 4 (Ref. 1). The Containment Pressure Relief Line is equipped with three quick-closing butterfly type isolation valves, one inside and two outside the containment which isolate automatically in accordance with requirements established in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation", and LCO 3.3.6, "Containment Purge System and Pressure Relief Line Isolation Instrumentation." The Containment Pressure Relief Line discharges to the atmosphere via the Containment Auxiliary Charcoal Filter System (i.e., a filter bank with roughing, HEPA and charcoal filters).

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side or may be unisolated under administrative control. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations during fuel movements.

APPLICABLE SAFETY ANALYSES

During movement of recently irradiated fuel assemblies within containment, the most severe radiological consequences result from a fuel handling accident involving handling recently irradiated fuel. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 5). Fuel handling accidents, analyzed in Reference 2, include dropping a single irradiated fuel assembly and handling tool or a heavy object onto other irradiated fuel assemblies. The release of radioactivity from the containment following a fuel handling accident is limited by the following:

a) The requirements of LCO 3.9.6, "Refueling Cavity Water Level;"

b) the minimum decay time of 84 hours prior to moving irradiated fuel; and,

c) the use of administrative controls to ensure prompt closure of any containment openings with direct access from the containment atmosphere to the outside atmosphere.

Containment penetrations satisfy Criterion 3 of 10 CFR 50.36.

(continued)

BASES

LCO

This LCO limits the consequences of a fuel handling accident involving handling recently irradiated fuel in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment purge system penetrations. For the OPERABLE containment purge system penetrations, this LCO ensures that these penetrations are isolable by the Containment Purge isolation instrumentation. The containment personnel airlock doors and the personnel access door in the equipment hatch closure plate may be open during movement of irradiated fuel provided that at least one door in each opening is capable of being closed in the event of a fuel handling accident. In addition, the LCO is modified by a Note allowing penetration flow paths with direct access from the containment atmosphere to the outside atmosphere to be unisolated under administrative controls. Administrative controls, consistent with Appendix B of Regulatory Guide 1.183 (Reference 3), are required to assure that, in the event of a fuel handling accident inside containment, at least one door in each personnel access opening will be closed following an evacuation of containment, and penetration flow paths unisolated under administrative control will be promptly closed. The administrative controls assure that:

1. appropriate personnel are aware of the open status of the doors and penetration flow paths during movement of irradiated fuel assemblies within containment, and

2. specified individuals are designated and readily available to direct and perform isolation of affected openings in the event of a fuel handling accident, and

3. any obstructions (e.g., cables and hoses) that would prevent rapid closure of an open flow path can be quickly removed. Any cables or hoses to be disconnected should not be supplying services that support personnel safety (e.g., breathing air), and

4. during fuel handling operations and core alterations, ventilation system and radiation monitor availability should be assessed with the goal of minimizing the potential for radioactive releases, following a potential accident, even further below that provided by the natural decay that occurs following reactor shutdown.

(continued)

BASES

LCO (continued)

The administrative controls must also be consistent with any pertinent assumptions in the dose analysis for the fuel handling accident. Note that the Indian Point 3 Final Safety Analysis Report (Reference 2) specifies: “No movement of irradiated fuel in the reactor is made until the reactor has been subcritical for at least 84 hours.” Therefore, the FSAR prohibits movement of any fuel that can be classified as “recently irradiated.”

APPLICABILITY

The containment penetration requirements are applicable during movement of recently irradiated fuel assemblies within containment because this is when there is a potential for the limiting fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODES 5 and 6, when movement of recently irradiated fuel assemblies within containment is not being conducted, the potential for the limiting fuel handling accident does not exist. Therefore, under these conditions no Technical Specification requirements are placed on containment penetration status.

However, if personnel access doors or containment penetration flow paths are unisolated during any movement of irradiated fuel assemblies in containment, administrative controls are established to ensure prompt closure of these openings in the event of a fuel handling accident.

ACTIONS

A.1

If the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, including the Containment Purge system isolation instrumentation not capable of automatic actuation when the purge and exhaust valves are open, the unit must be placed in a condition where the isolation function is not needed. This is accomplished by immediately suspending the movement of recently irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

This Surveillance demonstrates that each of the containment penetrations is either closed or capable of being closed under administrative control. The Surveillance on the open purge and exhaust valves will demonstrate that the valves are not blocked from closing. Also the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each valve is capable of being closed by an OPERABLE automatic containment purge and exhaust isolation signal.

The Surveillance is performed within 7 days of movement of recently irradiated fuel assemblies within containment. The Surveillance interval is selected to be commensurate with the 84-hour decay time that defines recently irradiated fuel. A surveillance before the start of refueling operations will not have to be repeated during the applicable period for this LCO. As such, this Surveillance ensures that a postulated fuel handling accident that releases fission product radioactivity within the containment will not result in a release of fission product radioactivity to the environment.

SR 3.9.3.2

This Surveillance demonstrates that each containment purge and exhaust valve actuates to its isolation position on an actual or simulated high radiation signal. The 92 day Frequency ensures that this SR is performed prior to this function being required and periodically thereafter. In LCO 3.3.6, the Containment Purge system isolation instrumentation requires a CHANNEL CHECK every 12 hours and a COT every 92 days to ensure the channel OPERABILITY during refueling operations. Every 24 months a CHANNEL CALIBRATION is performed. SR 3.6.3.5 demonstrates that the isolation time of each valve is in accordance with the Inservice Testing Program requirements.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.2 (continued)

These Surveillances performed during MODE 6 will ensure that the valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the containment.

REFERENCES

1. FSAR, Section 5.3.
2. FSAR, Section 14.2.
3. Regulatory Guide 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors”, July 2000.
4. 10 CFR 50 Appendix A, “General Design Criteria”, Criterion 19, Control Room.
5. Safety Evaluation Report (SER) for IP3 Amendment 224.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Residual Heat Removal (RHR) and Coolant Circulation – High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchanger(s), where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) or regulating service water or component cooling water flow. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200 °F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. One train of the RHR System is required to be operational in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to prevent this challenge. The LCO does permit securing the RHR pump for short durations, under the condition that the boron concentration is not diluted. This conditional securing of the RHR pump does not result in a challenge to the fission product barrier. The RHR System meets Criterion 4 of 10 CFR 50.36.

(continued)

BASES (continued)

LCO

Only one RHR loop is required for decay heat removal in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange. Only one RHR loop is required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. At least one RHR loop must be OPERABLE and in operation to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop includes an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. The flow path starts in loop 32 RCS hot leg and is returned to the RCS cold legs.

The LCO is modified by a Note that allows the required operating RHR loop to be removed from service for up to 1 hour per 8 hour period, provided no operations are permitted that would cause a reduction of the RCS boron concentration. Boron concentration reduction is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles and RCS to RHR isolation valve testing. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity.

APPLICABILITY

One RHR loop must be OPERABLE and in operation in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to provide decay heat removal. The 23 ft water level was selected because it corresponds to the 23 ft requirement established for fuel movement in LCO 3.9.6, "Refueling Cavity Water Level." Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4," Reactor Coolant System (RCS)", and Section 3.5, "Emergency Core Cooling Systems (ECCS)." RHR

(continued)

BASES

APPLICABILITY (continued)

loop requirements in MODE 6 with the water level < 23 ft are located in LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level."

ACTIONS

RHR loop requirements are met by having one RHR loop OPERABLE and in operation, except as permitted in the Note to the LCO.

A.1

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations.

A.2

If RHR loop requirements are not met, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition.

A.3

If RHR loop requirements are not met, actions shall be initiated and continued in order to satisfy RHR loop requirements. With the unit in MODE 6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

(continued)

BASES

ACTIONS (continued)

A.4

If RHR loop requirements are not met, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed, using at least a single barrier, within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that the RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the RHR System.

REFERENCES

1. FSAR, Section 6.2.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant, and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchangers where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) or regulating service water or component cooling water flow. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200 °F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to the boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant will eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Two trains of the RHR System are required to be OPERABLE, and one train in operation, in order to prevent this challenge.

The RHR System meets criterion 4 of 10 CFR 50.36.

(continued)

BASES (continued)

LCO

In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, both RHR loops must be OPERABLE. Additionally, one loop of RHR must be in operation in order to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop consists of an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path. The flow path starts in loop 32 RCS hot leg and is returned to the RCS cold legs.

APPLICABILITY

Two RHR loops are required to be OPERABLE, and one RHR loop must be in operation in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, to provide decay heat removal. Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). RHR loop requirements in MODE 6 with the water level ≥ 23 ft are located in LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level."

ACTIONS

A.1 and A.2

If less than the required number of RHR loops are OPERABLE, action shall be immediately initiated and continued until the RHR loop is restored to OPERABLE status and to operation or until ≥ 23 ft of water level is established above the reactor vessel flange. When the water level is ≥ 23 ft above the reactor vessel flange, the Applicability changes to that of LCO 3.9.4, and only one RHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

(continued)

BASES

ACTIONS (continued)

B.1

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations.

B.2

If no RHR loop is in operation, actions shall be initiated immediately, and continued, to restore one RHR loop to operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR loops and one operating RHR loop should be accomplished expeditiously.

B.3

If no RHR loop is in operation, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed, using at least a single barrier, within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures that dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. In addition, during operation of the RHR loop with the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 (continued)

water level in the vicinity of the reactor vessel nozzles, the RHR pump suction requirements must be met. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator for monitoring the RHR System in the control room.

SR 3.9.5.2

Verification that the required pump not in operation is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. FSAR, Section 6.2.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Refueling Cavity Water Level

BASES

BACKGROUND

The movement of irradiated fuel assemblies or performance of CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts, within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. During refueling, this maintains sufficient water level in the containment, refueling canal, fuel transfer canal, refueling cavity, and spent fuel pit. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to within RG 1.183 limits (Ref. 4).

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS and movement of irradiated fuel assemblies, the water level in the refueling canal and the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment, as postulated by Regulatory Guide 1.25 (Ref. 1). In the Fuel Handling Accident (FHA) analysis (Ref. 6), a fuel assembly is assumed to be dropped and damaged during refueling. It is assumed that all of the fuel rods in one assembly are damaged to the extent that all of the gap activity is released. The fuel handling accident is described in Reference 2.

Doses from the FHA are calculated in accordance with the Alternate Source Term methodology of Regulatory Guide 1.183 (Ref. 4). For water level of 23 ft or greater above the fuel, RG 1.183 specifies an overall decontamination factor of 200. There is no retention of noble gases in the water. The decay time prior to fuel movement is a minimum of 84 hours. Credit is not taken for removal of iodine by filters, nor is credit taken for isolation of release paths.

Using RG 1.183 methodology, all calculated offsite and control room doses are determined to be within the RG 1.183 specified fractions of the 10CFR50.67 limits for decay periods of $\geq$ 84 hours.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Further reductions in the amount of radioactivity potentially released following a fuel handling accident inside containment are expected because the containment will be isolated either automatically or through operator action following a fuel handling accident. Specifically, LCO 3.3.6, "Containment Purge System and Pressure Relief Line Isolation Instrumentation," requires the Operability of radiogas monitors R-11 and R-12, either of which could generate an automatic isolation signal, during the movement of irradiated fuel.

Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36.

LCO

A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits, as per Reference 6.

APPLICABILITY

LCO 3.9.6 is applicable during CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts, and when moving irradiated fuel assemblies within containment. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.14, "Spent Fuel Pit Water Level."

ACTIONS

A.1 and A.2

With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving CORE ALTERATIONS or movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of CORE ALTERATIONS and fuel movement shall not preclude completion of movement of a component to a safe position.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 2).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Regulatory Guide 1.25, March 23, 1972.
2. FSAR, Section 14.2.
3. NUREG-0800, Section 15.7.4.
4. Regulatory Guide 1.183, July 2002.
5. Safety Evaluation Report (SER) for IP3 Amendment 224.

TABLE OF CONTENTS

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs

LCO 3.0.1 through LCO 3.0.5 establish the general requirements applicable to all Specifications and apply under the stated conditions.

LCO 3.0.1

LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met.

LCO 3.0.2

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met, except as provided in LCO 3.0.5. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that:

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

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

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

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case.

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Additionally, if intentional entry into ACTIONS would result in redundant equipment being inoperable, alternatives should be used instead.

BASES

LCO 3.0.3

Not applicable.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.

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

LCO 3.0.5

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

a. The OPERABILITY of the equipment being returned to service or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

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

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO.

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

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known not to be met between required Surveillance performances.

Surveillances do not have to be performed when the system is in a specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a test exception are only applicable when the test exception is used as an allowable exception to the requirements of a Specification.

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

BASES

SR 3.0.1 (continued)

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the specified conditions in the Applicability due to the necessary parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to the specified condition where other necessary post maintenance tests can be completed.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per . . ." interval.

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

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per ..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

BASES

SR 3.0.2 (continued)

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

SR 3.0.3

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

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

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

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required) and impact on any analysis assumptions, in addition to unit conditions, planning,

BASES

SR 3.0.3 (continued)

availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the Corrective Action Program.

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

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

SR 3.0.4

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

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

BASES

SR 3.0.4 (continued)

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

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to specified condition changes. SR 3.0.4 does not restrict changing specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent entry into specified conditions in the Applicability that are required to comply with ACTIONS.

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

B 3.1 INTER-UNIT FUEL TRANSFER

B 3.1.1 Boron Concentration

BASES

BACKGROUND

The NRC has issued Amendment 246 for the inter-unit transfer of spent nuclear fuel (Ref. 1). The Amendment is based on evaluations conducted for each aspect of the inter-unit transfer of fuel as documented in Reference 2.

The limit on the boron concentration in the Spent Fuel Pit (SFP) and the Shielded Transfer Canister (STC) ensures that the fuel in the STC remains subcritical during postulated accidents. The soluble boron concentration offsets the reactivity addition due to the postulated accidents and is measured by chemical analysis of a representative sample of the water in each of the volumes.

APPLICABLE SAFETY ANALYSIS

As required by 10 CFR 50.68 (Ref. 3), if no credit for soluble boron in the STC is taken then, the k_{eff} of the STC fuel basket loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95 percent probability, 95 percent confidence level, if flooded with unborated water.

Reference 2 documents the results of a criticality analysis that demonstrates that the STC k_{eff} is less than or equal to 0.95 with the STC fuel basket loaded with fuel of the highest anticipated reactivity and the STC flooded with water at a temperature corresponding to the highest reactivity. The maximum calculated reactivity, which includes a margin for uncertainty in reactivity calculations, is performed for a combination of worst case tolerances and conditions, and is shown to be less than 0.95 with a 95 percent probability at a 95 percent confidence level. Under normal conditions, the water in the STC is assumed to be pure, unborated water, while under accident conditions, the soluble boron in the water is credited. A summary of the types of accidents analyzed and the soluble boron required to ensure the maximum k_{eff} remains below 0.95 is provided in Reference 2. These acceptance criteria are in accordance with 10 CFR 50.68(b) (Ref. 3).

The double contingency principle discussed in ANSI N16.1-1975 and the April 1978 NRC letter (Ref. 4) allows credit for soluble boron under other abnormal or accident conditions because only

BASES

APPLICABLE SAFETY ANALYSIS (continued)

a single accident need be considered at one time. For example, the postulated accident scenarios include dropping a fuel assembly on top of the STC basket, or accidental misloading of a fuel assembly in the STC basket. These events could increase the potential for criticality in the STC. To mitigate these postulated criticality related accidents, boron concentration is verified to be within the limits specified in LCO 3.1.1.

These events could increase the potential for criticality in the STC. The criticality accidents can only take place during or as a result of the movement of an assembly. For these accident occurrences, the presence of soluble boron in the spent fuel storage pit prevents criticality in the STC. Reference 2 describes multiple fuel assembly misloads and determined that in the limiting configuration a boron concentration of 1053 ppm was required to maintain k_{eff} less than or equal to 0.95.

The concentration of dissolved boron in the STC satisfies Criterion 2 of 10 CFR 50.36.

LCO

The boron concentration of the water in the spent fuel pit containing the STC and in the STC is required to be ≥ 2000 ppm. The specified concentration of dissolved boron preserves the assumptions used in the criticality accident scenarios as described in Reference 2. This concentration also preserves the criticality assumptions of the IP2 and IP3 spent fuel pools.

The LCO is modified by a Note indicating that the LCO is only applicable to the spent fuel pit when the STC is in the spent fuel pit. When the STC is not in the pit the boron concentration in the pit must continue to meet the requirements of IP3 Appendix A LCO 3.7.15 or IP2 Appendix A LCO 3.7.12.

APPLICABILITY

This LCO applies whenever one or more fuel assemblies are in the STC.

ACTIONS

A.1, A.2 and A.3

When the concentration of boron in the STC is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately

BASES

ACTIONS (continued)

suspending the movement of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. Prior to resuming movement of fuel assemblies, the concentration of boron must be restored. This does not preclude movement of a fuel assembly to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

When the concentration of boron in the STC is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This SR is modified by a Note indicating that the surveillance is only required to be performed if the STC is submerged in water in the spent fuel pool or if water is to be added to, or recirculated through, the STC. These are the only times when a change in STC boron concentration could potentially occur. In order to preserve the assumptions of the criticality analysis, the Note further requires that water added to, or recirculated through, the STC must meet the boron concentration requirements of LCO 3.1.1. This Note does not apply to the addition of steam to the STC (Reference 1).

This SR verifies that the concentration of boron in the spent fuel pit and the STC is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed. The initial surveillance within 4 hours prior to loading fuel into the STC and the 48 hour Frequency thereafter are appropriate because no major replenishment of spent fuel pit water is expected to take place over such a short period of time and any recirculation of water or water added to the STC will be accomplished using borated water at or above the required limit.

Whenever the STC is in the spent fuel pool a measurement of spent fuel pool boron concentration is equivalent to an STC boron concentration measurement.

BASES

REFERENCES

1. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 246 to Facility Operating License No. DPR-64, July 13, 2012.

2. Holtec Report HI-2094289, Licensing Report on the Inter-Unit Transfer of Spent Nuclear Fuel at Indian Point Energy Center, Revision 6.

3. 10 CFR 50.68, “Criticality Accident Requirements.”

4. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

B 3.1 INTER-UNIT FUEL TRANSFER

B 3.1.2 Shielded Transfer Canister (STC) Loading

BASES

BACKGROUND

As required by plant operations IP3 spent fuel is transferred to the IP2 spent fuel pit in order to maintain adequate fuel storage capacity in the IP3 spent fuel pit. IP3 spent fuel moved to the IP2 spent fuel pit is subsequently transferred to dry cask storage at the IPEC on-site Independent Spent Fuel Storage Installation (ISFSI) as part of spent fuel inventory management in the IP2 spent fuel pit. The NRC has issued Amendments 246 and 264 for the inter-unit transfer of spent nuclear fuel (Refs. 1 and 5).

Inter-unit fuel transfer operations are conducted using the Shielded Transfer Canister (STC) and the HI-TRAC 100D transfer cask. The STC is a bolted-lid pressure vessel with an internal fuel basket that accommodates up to twelve IP3 spent fuel assemblies. The STC is loaded in the IP3 spent fuel pit, placed into the HI-TRAC transfer cask in the Fuel Storage Building (FSB) truck bay, and moved outside the truck bay on air pads or other approved conveyance. The STC/HI-TRAC assemblage is transported from outside the IP3 FSB truck bay to just outside the IP2 FSB truck bay with a Vertical Cask Transporter (VCT) and moved into the IP2 FSB truck bay on a Low Profile Transporter.

The STC is removed from the HI-TRAC using the cask handling crane and placed into the IP2 spent fuel pit. The STC lid is removed and the IP3 fuel assemblies are moved to their designated IP2 wet storage rack cell locations with the spent fuel bridge crane in accordance with IP2 Appendix A TS LCO 3.7.13.

Fuel assemblies to be transferred are selected at IP3 based on the requirements for loading in the STC. The STC fuel loading requirements are such that the fuel selected for transfer to IP2 is suitable for storage in the designated IP2 spent fuel pit storage racks within the limits of IP2 Appendix A TS LCO 3.7.13 and there are open fuel cells available. Fuel move sheets will govern the transfer of the spent fuel from IP3 to IP2.

Table 3.1.2-1 “Minimum Burnup Requirements at Varying Initial Enrichments” is used to classify each assembly as either a Type 1 assembly or a Type 2 assembly based on initial U-235 enrichment and average assembly burnup. This classification is used to determine if, and where, the fuel assembly can be placed in the STC fuel basket. In the STC design, the fuel basket is divided into

BASES

BACKGROUND (continued)

twelve cells as shown in Figure 3.1.2-1, “Shielded Transfer Canister Layout (Top View)”. Type 2 assemblies are relatively less reactive assemblies and include any assembly that meets the minimum assembly average burnup at a given initial enrichment of Table 3.1.2-1. Type 2 assemblies may be stored in any cell in the STC subject to the additional restrictions of the LCO. These additional restrictions include post-irradiation cooling time, initial enrichment, allowable average burnup and decay heat of fuel and non fuel hardware as specified in Table 3.1.2-2 “Non Fuel Hardware Post Irradiation Cooling Times and Allowable Average Burnup” and Table 3.1.2-3 ”Allowable STC Loading Configurations”.

Type 1 assemblies are relatively more reactive assemblies and include any assembly that does not meet the minimum assembly average burnup at a given initial enrichment of Table 3.1.2-1. Type 1 fuel must be placed in the outer cells of the STC subject to the additional restrictions of the LCO. These additional restrictions include post-irradiation cooling time, initial enrichment, allowable average burnup and decay heat of fuel and non fuel hardware as specified in Tables 3.1.2-2 and 3.1.2-3.

Together, the limits on Type 1 and Type 2 fuel assemblies and associated non fuel hardware ensure the criticality, shielding, structural and thermal analyses performed for the STC remain bounding.

To ensure that fuel assemblies selected for transfer can be stored in the IP2 SFP only fuel assemblies with initial average enrichment ≤ 4.4 wt% U-235 and discharged prior to IP3 Cycle 12 can be placed in the STC basket. IP3 fuel assemblies V43 and V48 shall not be selected for transfer.

Fuel assemblies with an initial enrichment > 5.0 wt% U-235 are not shown on Table 3.1.2-1 and cannot be placed in the STC in accordance with TS 3.1.2.

APPLICABLE SAFETY ANALYSES

The STC has been analyzed for criticality prevention, heat rejection capability, shielding, and structural integrity to ensure safe transfer operations from the time that the STC is loaded at IP3 to the time it is unloaded at IP2 (Refs. 2 and 6).

As required by 10 CFR 50.68 (Ref. 3), if no credit for soluble boron in the STC is taken then, the k_{eff} of the STC fuel basket loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95 percent probability, 95 percent confidence level, if flooded with unborated water.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

Reference 2 documents the results of a criticality analysis that demonstrates that the STC k_{eff} is less than or equal to 0.95 with the STC fuel basket loaded with fuel of the highest anticipated reactivity and the STC flooded with water at a temperature corresponding to the highest reactivity. The maximum calculated reactivity, which includes a margin for uncertainty in reactivity calculations, is performed for a combination of worst case tolerances and conditions, and is shown to be less than 0.95 with a 95 percent probability at a 95 percent confidence level. Under normal conditions, the water in the STC is assumed to be pure, unborated water, while under accident conditions, the soluble boron in the water is credited. A summary of the types of accidents analyzed and the soluble boron required to ensure the maximum k_{eff} remains below 0.95 is provided in Reference 2. These acceptance criteria are in accordance with 10 CFR 50.68(b) (Ref. 3).

The criticality analysis and the limits on fuel selection prescribed in LCO 3.1.2 ensure that the effective neutron multiplication factor (k_{eff}) of a loaded STC in its most reactive configuration remains less than 0.95.

The double contingency principle discussed in ANSI N16.1-1975 and the April 1978 NRC letter (Ref. 4) allows credit for soluble boron under other abnormal or accident conditions because only a single accident need be considered at one time. For example, the accident scenarios include dropping a fuel assembly on top of the STC basket, or accidental misloading of a fuel assembly in the STC basket. These events could increase the potential for criticality in the STC. To mitigate these postulated criticality related accidents, boron concentration is verified to be within the limits specified in LCO 3.1.1, “Boron Concentration”.

Reference 2 documents the results of a thermal analysis that shows that the fuel cladding temperature remains below the acceptance criteria of 752^{o}F and 1058^{o}F, for normal and accident conditions respectively, at all times during inter-unit transfer and that the design pressure and temperature of the STC are not exceeded.

Reference 2 documents the results of a structural analysis that shows that the STC and HI-TRAC maintain their structural integrity under all normal, off-normal, and credible accident conditions.

BASES

APPLICABLE SAFETY ANALYSIS (continued)	Reference 2 documents the results of a shielding analysis that shows that the dose rates from the STC during the short time it is not inside the HI-TRAC are acceptable with appropriate radiation protection controls. Dose rates from the loaded HI-TRAC are shown to be low. The configuration of fuel assemblies in the STC satisfies Criterion 2 of 10 CFR 50.36.
LCO	Fuel assemblies stored in the spent fuel pit are classified in accordance with Table 3.1.2-1 based on initial enrichment and burnup which is indicative of fuel assembly reactivity. Based on this classification, fuel assembly placement in the STC cells is restricted in accordance with the classification of the fuel and the additional constraints established by this LCO. LCO 3.1.2.b is modified by a note stating that if one or more Type 1 assemblies are in the STC, cells 1, 2, 3, and 4 must be empty, with a cell blocker installed that prevents inserting fuel assemblies and/or non fuel hardware. The restriction preserves the assumptions of the bounding criticality analysis for Type 1 fuel assemblies placed only in the peripheral fuel cells.
APPLICABILITY	This LCO applies whenever one or more fuel assemblies are in the STC.
ACTIONS	<u>A.1.1</u> When the configuration of fuel assemblies or non fuel hardware in the STC is not in accordance with this LCO, one action is to make the necessary fuel assembly or non fuel hardware movement(s) to bring the configuration of the fuel in the STC into compliance with this LCO. This action restores the STC to an analyzed configuration. <u>OR</u> <u>A.1.2</u> When the configuration of fuel assemblies or non fuel hardware in the STC is not in accordance with this LCO, an optional action to restore compliance with the LCO is to move the fuel assembly or

BASES

ACTIONS (continued)	assemblies or non fuel hardware from the STC back into the IP3 spent fuel pool in accordance with Appendix A Technical Specification LCO 3.7.16. Either action places the fuel in equally safe locations. The completion time of "Immediately" is appropriate because fuel located in the STC may be in an unanalyzed condition and action is required to be initiated and completed without delay to restore the fuel location to an analyzed configuration.
SURVEILLANCE REQUIREMENTS	SR 3.1.2.1 This SR verifies by administrative means that the fuel assembly meets the requirements of the STC location in which it is to be placed. This SR ensures the LCO limits for fuel selection and location in the STC are met and the supporting technical analyses remain bounding for all inter-unit transfer operations. SR 3.1.2.2 This SR verifies by visual inspection that a cell blocker is installed prior to placing a Type 1 fuel assembly and/or non fuel hardware in the STC. This SR ensures that a Type 1 fuel assembly cannot be inserted into STC cells 1, 2, 3, and 4.

REFERENCES

1. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 246 to Facility Operating License No. DPR-64, July 13, 2012.

2. Holtec Report HI-2094289, Licensing Report on the Inter-Unit Transfer of Spent Nuclear Fuel at Indian Point Energy Center, Revision 6.

3. 10 CFR 50.68, "Criticality Accident Requirements."

4. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

BASES

REFERENCES (continued)

5. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No 264 to Facility Operating License No. DPR-64, December 22, 2017

6. Holtec Report HI-2094289, Licensing Report on the Inter-Unit Transfer of Spent Nuclear Fuel at Indian Point Energy Center, Revision 10

BASES

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that the water used for level restoration must meet the boron concentration requirement of LCO 3.1.1. This requirement preserves the assumptions of the criticality analysis.

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR verifies that the STC initial water level is within limit by verifying that steam is emitted from the STC drain tube during STC water level establishment and that the required volume of water is removed from the STC. As long as this SR is met, the analyzed accident assumptions are met.

REFERENCES

1. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 268 to Facility Operating License No. DPR-26, July 13, 2012.

2. Holtec Report HI-2094289, Licensing Report on the Inter-Unit Transfer of Spent Nuclear Fuel at Indian Point Energy Center, Revision 6.

B 3.1 INTER-UNIT FUEL TRANSFER

B 3.1.4 Shielded Transfer Canister (STC) Pressure Rise

BASES

BACKGROUND

The NRC has issued Amendment 246 for the inter-unit transfer of spent nuclear fuel (Ref. 1). The Amendment is based on evaluations conducted for each aspect of the inter-unit transfer of fuel as documented in Reference 2.

The limits on the STC pressure rise ensures that there has not been an accidental misloading of a high decay heat fuel assembly or the misloading of multiple assemblies and that there is not a significant amount of air in the STC.

APPLICABLE SAFETY ANALYSES

The accidental misloading of a high decay heat fuel assembly, the accidental misloading of multiple assemblies, or the accidental introduction of a significant amount of air into the STC would be detected based on a comparison of predicted and as measured STC pressures as a function of time. Thermal analyses have been performed (Ref. 2) that predict an STC pressure rise of no more than 0.2 psi/hour after an STC loaded with the design basis heat load is placed in the HI-TRAC and the STC is sealed.

The STC pressure rise limit satisfies Criterion 2 of 10 CFR 50.36.

LCO

The STC pressure rise is required to be ≤ 0.2 psi/hour averaged over a rolling 4 hour period prior to TRANSFER OPERATIONS when the STC is in the HI-TRAC and the STC lid has been installed and the STC water level established. Pressure measurements shall be taken once upon establishing required water level and hourly thereafter over a 24 hour period.

Monitoring the STC pressure rise ensures that should the pressure rise limit be exceeded, appropriate actions are taken in a timely manner to return the STC to the IP3 spent fuel pool. Also note that the 24 hour STC pressure test will also be a check on the thermal properties of the STC and HI-TRAC system, such that if there were any significant changes in the thermal properties it would be expected to show as anomalous readings during the pressure test.

This LCO preserves the assumptions of the safety analyses for the STC.

BASES

APPLICABILITY

Over a 24 hour period after successful completion of LCO 3.1.3 and prior to TRANSFER OPERATIONS when the STC is in the HI-TRAC and the STC lid has been installed.

ACTIONS

A.1.1

The completion time of “Immediately” is appropriate because fuel located in the STC may be in an unanalyzed condition and action is required to be initiated and completed without delay to prevent overpressurization of the STC.

A.1.2

Required Action A.1.2 is modified by a Note indicating that the water used for recirculation must meet the boron concentration requirement of LCO 3.1.1. This requirement preserves the assumptions of the criticality analysis.

The completion time of “Immediately” is appropriate because fuel located in the STC may be in an unanalyzed condition and action is required to be initiated without delay to prevent overpressurization of the STC.

A.1.3

The completion time of “Immediately” is appropriate because fuel located in the STC may be in an unanalyzed condition and action is required to be initiated and completed without delay to prevent overpressurization of the STC.

B.1.1

The completion time of 12 hours is appropriate because fuel located in the STC may be in an unanalyzed condition and action is required to be initiated to restore fuel location to an analyzed configuration. This timeframe considers the time required to complete this action and that a vent path has been established.

B.1.2

The completion time of 24 hours is appropriate because fuel located in the STC may be in an unanalyzed condition and action is required to be initiated and completed to restore fuel location to an analyzed configuration. This timeframe considers the time required to complete this action.

BASES

ACTIONS (continued)

C.1

The completion time of 24 hours is appropriate because although the fuel located in the STC is not in an unanalyzed condition prompt action is required to develop and initiate corrective actions to return the STC to compliance with LCO 3.1.3 and LCO 3.1.4.

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

This SR verifies by direct measurement that the STC cavity pressure is within limit. As long as this SR is met, the analyzed accident assumptions are met.

SR 3.1.4.2

This SR verifies that an ASME code compliant pressure relief valve or rupture disc and two channels of pressure instrumentation of the required range and accuracy are installed on the STC during performance of the SR. The pressure relief valve or rupture disc protects the STC pressure boundary until it has been demonstrated that there has not been an accidental misloading of a high decay heat fuel assembly or the misloading of multiple assemblies and that there is not a significant amount of air in the STC.

REFERENCES

1. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 268 to Facility Operating License No. DPR-26, July 13, 2012.

2. Holtec Report HI-2094289, Licensing Report on the Inter-Unit Transfer of Spent Nuclear Fuel at Indian Point Energy Center, Revision 6.

B 3.1 INTER-UNIT FUEL TRANSFER

B 3.1.5 Shielded Transfer Canister (STC) Unloading

BASES

BACKGROUND	The NRC has issued Amendment 246 for the inter-unit transfer of spent nuclear fuel (Ref. 1). The Amendment is based on evaluations conducted for each aspect of the inter-unit transfer of fuel as documented in Reference 2. The limits on STC unloading ensures that the fuel in the STC and the IP2 spent fuel pool remains subcritical during normal operations and postulated accidents. The STC is removed from the HI-TRAC using the IP2 cask handling crane and placed into the IP2 spent fuel pit. The STC lid is removed and the IP3 fuel assemblies are moved to their designated IP2 wet storage rack cell locations with the spent fuel bridge crane in accordance with IP2 Appendix A TS LCO 3.7.13. Fuel assemblies to be transferred are selected at IP3 based on the requirements for loading in the STC as specified in LCO 3.1.2. The STC fuel loading requirements are such that the fuel selected for transfer to IP2 is suitable for storage in the IP2 spent fuel pit within the limits of IP2 Appendix A TS LCO 3.7.13 and there are open fuel cells available. Fuel move sheets will govern the transfer of the spent fuel from IP3 to IP2.
APPLICABLE SAFETY ANALYSES	The STC has been analyzed for criticality prevention, heat rejection capability, shielding, and structural integrity to ensure safe transfer operations from the time that the STC is loaded at IP3 to the time it is unloaded at IP2 (Ref. 2). As required by 10 CFR 50.68 (Ref. 3), if no credit for soluble boron in the STC is taken then, the k-effective of the spent fuel storage racks loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95 percent probability, 95 percent confidence level, if flooded with unborated water. Reference 2 documents the results of a criticality analysis that demonstrates that the STC k_{eff} is less than or equal to 0.95 with the STC fuel basket loaded with fuel of the highest anticipated reactivity and the STC flooded with water at a temperature corresponding to the highest reactivity. The maximum calculated reactivity, which includes

BASES

APPLICABLE SAFETY ANALYSIS (continued)

a margin for uncertainty in reactivity calculations, is performed for a combination of worst case tolerances and conditions, and is shown to be less than 0.95 with a 95 percent probability at a 95 percent confidence level. Under normal conditions, the water in the STC is assumed to be pure, unborated water, while under accident conditions, the soluble boron in the water is credited. A summary of the types of accidents analyzed and the soluble boron required to ensure the maximum k_{eff} remains below 0.95 is provided in Reference 2. These acceptance criteria are in accordance with 10 CFR 50.68(b) (Ref. 3).

The criticality analysis and the limits on fuel selection prescribed in LCO 3.1.2 ensure that the effective neutron multiplication factor (k_{eff}) of a loaded STC in its most reactive configuration remains less than 0.95. In addition, the criticality analysis and the limits on fuel selection prescribed in Appendix A TS LCO 3.7.13 ensure that k_{eff} remains below 0.95 if the spent fuel pool is flooded with borated water and below 1.0 if flood with unborated water both at the 95 percent probability, 95 percent confidence level.

The double contingency principle discussed in ANSI N16.1-1975 and the April 1978 NRC letter (Ref. 4) allows credit for soluble boron under other abnormal or accident conditions because only a single accident need be considered at one time. For example, the accident scenarios include dropping a fuel assembly on top of the STC basket, or accidental misloading of a fuel assembly in the STC basket. These events could increase the potential for criticality in the STC. To mitigate these postulated criticality related accidents, boron concentration is verified to be within the limits specified in LCO 3.1.1, “Boron Concentration”.

Reference 2 documents the results of a thermal analysis that shows that the fuel cladding temperature remains below the acceptance criteria of 752°F and 1058°F, for normal and accident conditions respectively, at all times during inter-unit transfer and that the design pressure and temperature of the STC are not exceeded.

Reference 2 documents the results of a structural analysis that shows that the STC and HI-TRAC maintain their structural integrity under all normal, off-normal, and credible accident conditions.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

Reference 2 documents the results of a shielding analysis that shows that the dose rates from the STC during the short time it is not inside the HI-TRAC are acceptable with appropriate radiation protection controls. Dose rates from the loaded HI-TRAC are shown to be low.

The configuration of fuel assemblies in the STC satisfies Criterion 2 of 10 CFR 50.36.

LCO

LCO 3.1.5 governs the presence of the STC in the IP2 spent fuel pit. The STC arrives at IP2 with its bolted lid in place, which preserves the fuel types and fuel locations established at IP3 when the STC was loaded. Once the STC lid is removed at IP2, this LCO requires that a transferred fuel assembly be in one of three places:

1. In an approved IP2 spent fuel pit storage rack location per Appendix A TS LCO 3.7.13, or
2. In an authorized STC fuel basket cell, or
3. In transit between these two locations.

This LCO preserves the assumptions of the safety analyses for the STC and the IP2 spent fuel pit.

This LCO is modified by two notes. Note 1 specifies that only IP3 spent fuel assemblies are permitted to be in the STC because the STC design and analysis are based on IP3 fuel assemblies. Therefore, loading of IP2 fuel assemblies in the STC is not authorized. Note 2 specifies that once each IP3 spent fuel assembly is removed from the STC and placed in an IP2 spent fuel pit storage rack location and released from the spent fuel bridge crane, it may not be returned to the STC. This note prevents loading IP3 fuel out of the IP2 spent fuel pit for transfer back to the STC. This is not an authorized evolution.

APPLICABILITY

The LCO is applicable whenever the STC is in the IP2 spent fuel pit.

ACTIONS

A.1

When any IP3 spent fuel assembly transferred to the IP2 spent fuel pit is not in one of the three authorized locations, LCO 3.1.5 is

BASES

ACTIONS (continued)	not met. Required Action A.1 specifies that action begin immediately to restore compliance with the LCO. The affected fuel assemblies must be placed in an authorized location without delay. The completion time of "Immediately" is appropriate because fuel located in the STC or the spent fuel pit racks may be in an unanalyzed condition and action is required to be initiated and completed without delay to restore fuel location to an analyzed configuration.
SURVEILLANCE REQUIREMENTS	<u>SR 3.1.5.1</u> SR 3.1.5.1 requires that any IP3 fuel assembly being returned to the STC be verified by administrative means to have been returned to the same STC fuel basket cell location from which it was removed. This SR ensures that the loading pattern authorized when the STC was loaded at IP3 is preserved. This SR does not apply for placing the IP3 fuel assembly in a IP2 spent fuel pit cell location because that process is governed by IP2 Appendix A TS LCO 3.7.13 and a fuel move sheet is required to place the IP3 fuel assembly in an approved location in the IP2 spent fuel pit storage racks.
REFERENCES	1. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 246 to Facility Operating License No. DPR-64, July 13, 2012. 2. Holtec Report HI-2094289, Licensing Report on the Inter-Unit Transfer of Spent Nuclear Fuel at Indian Point Energy Center, Revision 6. 3. 10 CFR 50.68, "Criticality Accident Requirements." 4. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).