Duke Energy®

JAMES R MORRIS
Vice President

Catawba Nuclear Station
4800 Concord Road / CN01VP
York, SC 29745-9635

803 831 4251
803 831 3221 fax

December 11, 2007

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

Subject: Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC (Duke)
Catawba Nuclear Station, Units 1 and 2
Docket Numbers 50-413 and 50-414
McGuire Nuclear Station, Units 1 and 2
Docket Numbers 50-369 and 50-370
Proposed Technical Specification (TS) Amendment to Relax Completion Times and Surveillance Intervals for the Reactor Trip System (RTS) Instrumentation TS 3.3.1, Engineered Safety Feature Actuation System (ESFAS) Instrumentation TS 3.3.2, Containment Air Release and Addition Isolation Instrumentation TS 3.3.6, (Catawba only) and Boron Dilution Mitigation System (BDMS) TS 3.3.9, (Catawba only)

References:

1) Letter from Thomas H. Essig (NRC) to Louis F. Liberatori Jr. (Westinghouse), Review of Westinghouse Owners Group Topical Reports WCAP-14333P and WCAP-14334NP, dated May 1995, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times" dated July 15, 1998
2) Letter from W. D. Beckner (NRC) to A. Pietrangelo (Nuclear Energy Institute) dated April 2, 2003
3) Letter from W. H. Ruland, NRR to R. H. Bryan, Westinghouse Owners Group, Acceptance for Referencing of Topical Report WCAP-15376-P. Rev. 0, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times" dated December 20, 2002
4) Letter from W. D. Beckner (NRC) to A. Pietrangelo (Nuclear Energy Institute) dated August 30, 2002

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Pursuant to 10 CFR 50.90, Duke is requesting an amendment to the Catawba and McGuire Nuclear Station Facility Operating License and Technical Specifications (TS).

The proposed changes permit relaxation of the allowed bypass test times and Completion Times (CTs) for Limiting Condition for Operation (LCOs) 3.3.1, Reactor Trip System (RTS) Instrumentation; 3.3.2, Engineered Safety Feature Actuation System (ESFAS) Instrumentation; 3.3.6, Containment Air Release and Addition Isolation Instrumentation (Catawba only) and 3.3.9, Boron Dilution Mitigation System (BDMS) (Catawba only).

Additionally, Duke proposes to increase the CT and the bypass time for the reactor trip breakers and increase the Surveillance Test Intervals (STIs) for the reactor trip breakers, master relays, logic cabinets, and analog channels. These TS changes will reduce the required testing on the RTS components without significantly impacting their reliability, and will reduce the potential for reactor trips and actuation of engineered safety features associated with the testing of the components. The CT extensions for the reactor trip breakers will provide additional time to complete test and maintenance activities while at power, potentially reducing the number of forced outages related to compliance with reactor trip breaker CTs, and will provide consistency with the CTs for the logic cabinets.

The above described changes have been either generically evaluated in WCAP-14333-P-A, Revision 1 and WCAP-15376-P-A, Revision 1 or have been supported by plant-specific analysis for those changes which are plant specific and therefore not evaluated in these WCAPs. Reference 1 documents the NRC approval of WCAP-14333 for referencing in plant-specific submittals. Reference 3 documents the NRC approval of WCAP-15376 for referencing in plant-specific submittals.

The changes in WCAP-14333-P-A are similar to those proposed by the Technical Specification Task Force (TSTF) in the proposed changes to NUREG-1431. The proposed changes were documented in Standard Technical Specification Change Traveler TSTF-418, Revision 2, "RPS and ESFAS Test Times and Completion Times (WCAP-14333)," that the NRC approved by means of Reference 2. Duke has reviewed TSTF-418, Revision 2 and has concluded that it is applicable to Catawba and McGuire Units 1 and 2.

The changes in WCAP-15376-P-A are similar to those proposed by the TSTF in the proposed changes to NUREG-1431. The proposed changes were documented in TSTF-411, Revision 1, "Surveillance Test Interval Extensions for Components of the Reactor Protection System," that the NRC approved by means of Reference 4. Duke has reviewed TSTF-411, Revision 1 and has concluded that it is applicable to Catawba and McGuire Units 1 and 2.

Also as discussed in the submittal, several additional clarification related changes are being proposed to the TS Bases for Catawba and McGuire that are not specifically related to the above TSTFs. These changes are being proposed in this submittal since they affect the same TS Bases sections as do the TSTFs.

Enclosure 1 provides a description of the proposed changes, background, the technical and regulatory analyses, and the basis for the categorical exclusion from performing an Environmental Assessment/Impact Statement in conjunction with this amendment request.

Attachments 1 and 2 provide marked copies of the affected TS pages for Catawba and McGuire, respectively, showing the proposed changes. Attachments 3 and 4 provide marked copies of the affected TS Bases pages for Catawba and McGuire, respectively, showing the proposed changes. Attachment 5 provides a summary of regulatory commitments made in this submittal.

Attachment 6 documents the Applicability of WCAP-14333-P-A and WCAP-15376-P-A Analyses to the Catawba Nuclear Station. Attachment 7 documents the Applicability of WCAP-14333-P-A and WCAP-15376-P-A Analyses to the McGuire Nuclear Station. Westinghouse has determined that information contained in Attachments 6 and 7 is proprietary, and is thereby supported by an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR 2.390.

Accordingly, it is respectfully requested that the information that is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR 2.390. This letter transmits proprietary and non-proprietary copies of Attachments 6 and 7.

Attachment 8 includes Westinghouse authorization letter CAW-04-1838, its accompanying affidavit, Proprietary Information Notice, and Copyright Notice. Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse affidavit should reference CAW-04-1838 and should be addressed to J. A. Gresham, Manager of Regulatory Compliance and Plant Licensing, Westinghouse Electric Company, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Implementation of this amendment to the Catawba and McGuire Facility Operating Licenses and TS will not impact the Catawba or McGuire Updated Final Safety Analysis Reports (UFSAR).

Duke is requesting a 90-day implementation period for this amendment. The 90 days are necessary due to the number of TS being revised and the required document and process changes associated with this amendment.

In accordance with Duke administrative procedures and the Quality Assurance Program Topical Report, this proposed amendment has been previously reviewed and approved by the Catawba and McGuire Plant Operations Review Committees and the Duke Nuclear Safety Review Board.

Pursuant to 10 CFR 50.91, a copy of this proposed amendment is being sent to the appropriate state officials.

Inquiries on this matter should be directed to L. J. Rudy at (803) 831-3084 (Catawba) or P. T. Vu at (704) 875-4302 (McGuire).

Very truly yours,

J. R. Morris

LJR/s

Enclosure: 1) - EVALUATION

Attachments:
1) - MARKUP of TS PAGES FOR CATAWBA
2) - MARKUP of TS PAGES FOR MCGUIRE
3) - PROPOSED TS BASES CHANGES FOR CATAWBA
4) - PROPOSED TS BASES CHANGES FOR MCGUIRE
5) - SUMMARY OF REGULATORY COMMITMENTS
6A) - TOPICAL REPORT APPLICABILITY DETERMINATION FOR CATAWBA (PROPRIETARY)
6B) - TOPICAL REPORT APPLICABILITY DETERMINATION FOR CATAWBA (NON-PROPRIETARY)
7A) - TOPICAL REPORT APPLICABILITY DETERMINATION FOR MCGUIRE (PROPRIETARY)
7B) - TOPICAL REPORT APPLICABILITY DETERMINATION FOR MCGUIRE (NON-PROPRIETARY)
8) - TOPICAL REPORT APPLICABILITY DETERMINATION PROPRIETARY DETERMINATION

J. R. Morris affirms that he is the person who subscribed his name to the foregoing statement, and that all statements and matters set forth herein are true and correct to the best of his knowledge.

J. R. Morris, Site Vice President

Subscribed and sworn to me: 12-11-2007
Date

Notary Public

My commission expires: 7-10-2012
Date

SEAL

xc (with enclosure and attachments):

W. D. Travers
U.S. Nuclear Regulatory Commission
Regional Administrator, Region II
Atlanta Federal Center
61 Forsyth St., SW, Suite 23T85
Atlanta, GA 30303

A. T. Sabisch
Senior Resident Inspector (Catawba)
U.S. Nuclear Regulatory Commission
Catawba Nuclear Station

J. B. Brady
Senior Resident Inspector (McGuire)
U.S. Nuclear Regulatory Commission
McGuire Nuclear Station

J. F. Stang, Jr. (addressee only)
NRC Senior Project Manager (Catawba and McGuire)
U.S. Nuclear Regulatory Commission
One White Flint North, Mail Stop 8 G9A
11555 Rockville Pike
Rockville, MD 20852-2738

S. E. Jenkins
Section Manager
Division of Waste Management
South Carolina Department of Health and Environmental Control
2600 Bull St.
Columbia, SC 29201

B. O. Hall
Section Chief
Division of Environmental Health, Radiation Protection Section
North Carolina Department of Environment and Natural Resources
1645 Mail Service Center
Raleigh, NC 27699-1645

bxc (with enclosure and attachments):

R. D. Hart	(CN01RC)
L. J. Rudy	(CN01RC)
P. T. Vu	(MG01RC)
R. L. Gill	(EC05O)
G. F. Winkel	(EC05N)

NCMPA-1
NCEMC
PMPA
SREC
Catawba Document Control File 801.01
McGuire Document Control File 801.01
RGC Date File
ELL-EC05O

ENCLOSURE 1

EVALUATION

EVALUATION

1.0 DESCRIPTION

Duke proposes to change the Catawba Nuclear Station (CNS) and McGuire Nuclear Station (MNS) requirements for TS 3.3.1, Reactor Trip System (RTS) Instrumentation (CNS & MNS), TS 3.3.2, Engineered Safety Feature Actuation System (ESFAS) Instrumentation (CNS & MNS), TS 3.3.6, Containment Air Release and Addition Isolation Instrumentation (CNS only), and TS 3.3.9, Boron Dilution Mitigation System (BDMS) (CNS only) to incorporate the changes proposed in the following Technical Specification Task Force (TSTF) travelers.

TS 3.3.6 in TSTF-411 Revision 1 is titled "Containment Purge and Exhaust Isolation Instrumentation." At McGuire, TS 3.3.6 was deleted under TS Amendment 243/224 approved by the NRC on July 26, 2007. At Catawba, TS 3.3.6 was modified under TS Amendment 196/189 approved by the NRC on March 20, 2002. This TS Amendment excluded the containment purge ventilation system and hydrogen purge system containment isolation valves from the instrumentation testing requirements in TS 3.3.6. The change left the Containment Air Release and Addition System requirements in TS 3.3.6 and revised the title of TS 3.3.6 to "Containment Air Release and Addition Isolation Instrumentation."

1. The proposed changes are consistent with approved TSTF-418, Revision 2 with exceptions noted in the applicable descriptions of changes. These revisions are those that have been generically approved in WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times."

2. The proposed changes to Condition F are consistent with NRC approved TSTF-246, Revision 0, "RTS Instrumentation, 3.3.1 Condition F Completion Time."

3. The proposed changes are consistent with approved TSTF-411, Revision 1 with exceptions noted in the applicable descriptions of changes. These revisions are those that have been generically approved in WCAP-15376-P-A, Revision 0, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times."

2.0 Proposed Changes

The TS changes for Catawba are as follows:

LCO 3.3.1, RTS Instrumentation		
Affected Condition	**Affected Instrumentation**	**Proposed Change**
Condition D	• Power Range Neutron Flux-High • Power Range Neutron Flux -High Positive Rate	Existing NOTE - Bypass Test Time from 4 hours to 12 hours
		Required Action D revised to extend time before placing in tripped condition from 6 hours to 72 hours (and to extend time to be in Mode 3 from 12 hours to 78 hours) and is revised and restructured to reduce potential for confusion.
Condition E	• Power Range Neutron Flux - Low • Overtemperature Delta-T • Overpower Delta-T • Pressurizer Pressure - High • Steam Generator (SG) Water Level - Low Low	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours.
		Required Action E.1: Place channel in trip changed from 6 hours to 72 hours
		Required Action E.2: Be in Mode 3 changed from 12 hours to 78 hours
Condition F	• Intermediate Range Neutron Flux	Required Action F.1: Reduce thermal power to < P-6 changed from 2 hours to 24 hours
		Required Action F.2: Increase thermal power to > P-10 changed from 2 hours to 24 hours
Condition L	• Pressurizer Pressure - Low • Pressurizer Water Level - High • Reactor Coolant Flow - Low: Two Loops • Undervoltage RCPs • Underfrequency RCPs	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours.
		Required Action L.1: Place channel in trip changed from 6 hours to 72 hours
		Required Action L.2: Reduce thermal power to < P-7 changed from 12 hours to 78 hours
Condition M	• Reactor Coolant Flow - Low: Single Loop	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours.
		Required Action M.1: Place channel in trip changed from 6 hours to 72 hours
		Required Action M.2: Reduce thermal power to < P-8 changed from 10 hours to 76 hours
Condition N	• Turbine Trip - Stop Valve EH Pressure Low	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours.
		Required Action N.1: Place channel in trip changed from 6 hours to 72 hours

		Required Action N.2: Reduce thermal power to < P-9 changed from 10 hours to 76 hours
Condition O	• Turbine Trip - Turbine Stop Valve Closure	Required Action O.1: Place channel in trip changed from 6 hours to 72 hours
		Required Action O.2: Reduce thermal power to < P-9 changed from 10 hours to 76 hours
Condition P	• Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS) • Automatic Trip Logic (Modes 1 and 2)	Required Action P.1: Restore train to OPERABLE status changed from 6 hours to 24 hours
		Required Action P.2: Be in Mode 3 changed from 12 hours to 30 hours
Condition Q	• Reactor Trip Breakers	Note 1: One train Bypass time changed from 2 to 4 hours
		Note 2: Deleted one RTB bypass time
		Required Action Q.1: Restore train to OPERABLE status changed from 1 hr to 24 hours
		Required Action Q.2: Be in Mode 3 changed from 7 hrs to 30 hrs
SR 3.3.1.4	• Reactor Trip Breakers • Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	TADOT frequency changed from 31 days to 62 days on a staggered test basis.
SR 3.3.1.5	• Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS) • Low Power Reactor Trips Block, P-7 • Automatic Trip Logic	Actuation Logic Test frequency changed from 31 days to 92 days on a staggered test basis.
SR 3.3.1.7	• Power Range Neutron Flux-High • Power Range Neutron Flux-High Positive Rate • Source Range Neutron Flux (Modes 3,4, & 5) • Overtemperature Delta-T • Overpower Delta-T • Pressurizer Pressure o Low o High • Pressurizer Water Level - High • Reactor Coolant Flow - Low o Single Loop o Two Loops • Steam Generator (SG) Water Level - Low-Low	Channel Operational Test frequency changed from 92 days to 184 days.

SR 3.3.1.8	• Power Range Neutron Flux - Low • Intermediate Range Neutron Flux • Source Range Neutron Flux	Note that states "Only required when not performed within previous 92 days", frequency changed from 92 days to 184 days.
		Channel Operational Test frequency changed from 92 days to 184 days.

LCO 3.3.2, ESFAS Instrumentation		
Affected Condition	**Affected Instrumentation**	**Proposed Change**
Condition C	• Automatic Actuation Logic and Actuation Relays o Safety Injection o Containment Spray o Containment Isolation - Phase A o Containment Isolation - Phase B o Automatic Switchover to Containment Sump	Required Action C.1: Restore train to OPERABLE status changed from 6 hours to 24 hours
		Required Action C.2.1: Be in Mode 3 changed from 12 hours to 30 hours
		Required Action C.2.2: Be in Mode 5 changed from 42 hours to 60 hours
Condition D	• Safety Injection o Containment Pressure - High o Pressurizer Pressure - Low • Steam Line Isolation o Steam Line Pressure - Low o Steam Line Pressure - Negative Rate High • Feedwater Isolation o SG Water Level - High High (P-14) • Auxiliary Feedwater o SG Water Level - Low Low o Loss of Offsite Power	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours.
		Required Action D.1: Place channel in trip changed from 6 hours to 72 hours
		Required Action D.2.1: Be in Mode 3 changed from 12 hours to 78 hours
		Required Action D.2.2: Be in Mode 4 changed from 18 hours to 84 hours
Condition E	• Containment Spray o Containment Pressure - High High • Containment Isolation - Phase B o Containment Pressure - High High • Steam Line Isolation o Containment Pressure - High	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours.
		Required Action E.1: Place channel in bypass changed from 6 hours to 72 hours
		Required Action E.2.1: Be in Mode 3 changed from 12 hours to 78 hours
		Required Action E.2.2: Be in Mode 4 changed from 18 hours to 84 hours

	High	
Condition H	• Automatic Actuation Logic and Actuation Relays o Steam Line Isolation o Feedwater Isolation o Auxiliary Feedwater	Required Action H.1: Restore train to OPERABLE status changed from 6 hours to 24 hours
		Required Action H.2.1: Be in Mode 3 changed from 12 hours to 30 hours
		Required Action H.2.2: Be in Mode 4 changed from 18 hours to 36 hours
Condition I	• Turbine Trip o Automatic Actuation Logic and Actuation Relays	Required Action I.1: Restore train to OPERABLE status changed from 6 hours to 24 hours
		Required Action I.2: Be in Mode 3 changed from 12 hours to 30 hours
Condition J	• Turbine Trip o SG Water Level - High High (P-14) • Feedwater Isolation o Tavg - Low coincident with Reactor Trip, P-4	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours.
		Required Action J.1: Place channel in trip changed from 6 hours to 72 hours
		Required Action J.2: Be in Mode 3 changed from 12 hours to 78 hours
SR 3.3.2.2	• Automatic Actuation Logic and Actuation Relays o Safety Injection o Containment Spray o Containment Isolation - Phase A o Containment Isolation - Phase B o Steam Line Isolation o Turbine Trip and Feedwater Isolation o Auxiliary Feedwater o Automatic Switchover to Containment Sump • Turbine Trip and Feedwater Isolation - SG Water Level - High High (P-14)	Actuation Logic Test frequency Changed from 31 days to 92 days on a staggered test basis.

SR 3.3.2.4	• Automatic Actuation Logic and Actuation Relays o Safety Injection o Containment Spray o Containment Isolation - Phase A o Containment Isolation - Phase B o Steam Line Isolation o Turbine Trip and Feedwater Isolation o Auxiliary Feedwater o Automatic Switchover to Containment Sump • Turbine Trip and Feedwater Isolation - SG Water Level - High High (P-14)	Master Relay Test frequency Changed from 31 days to 92 days on a staggered test basis.
SR 3.3.2.5	• Safety Injection o Containment Pressure - High o Pressurizer Pressure - Low • Containment Spray o Containment Pressure - High High • Containment Isolation - Phase B o Containment Pressure - High High • Steam Line Isolation o Containment Pressure - High High o Steam Line Pressure - Low o Steam Line Pressure Negative Rate - High • Turbine Trip and Feedwater Isolation o SG Water Level - High High (P-14) o Feedwater Isolation - Tave - Low coincident with reactor trip, P-4 • Auxiliary Feedwater o SG Water Level - Low Low • ESFAS Interlocks o Pressurizer Pressure, P-11 o Tave - Low Low, P-12	Channel Operational Test Frequency Changed from 92 days to 184 days.

LCO 3.3.6, Containment Air Release and Addition Isolation Instrumentation		
Affected Condition or Surveillance Requirement	**Affected Instrumentation**	**Proposed Change**
SR 3.3.6.1	• Automatic Actuation Logic and Actuation Relays	Revised SR frequency from 31 days to 92 days on a staggered test basis.
SR 3.3.6.2	• Automatic Actuation Logic and Actuation Relays	Revised SR frequency from 31 days to 92 days on a staggered test basis.

LCO 3.3.9, Boron Dilution Mitigation System		
Affected Condition or Surveillance Requirement	**Affected Instrumentation**	**Proposed Change**
SR 3.3.9.6	• BDMS Instrumentation	Channel Operational Test Frequency Changed from 92 days to 184 days.

The TS changes for McGuire are as follows:

LCO 3.3.1, RTS Instrumentation		
Affected Condition	**Affected Instrumentation**	**Proposed Change**
Condition D	• Power Range Neutron Flux-High • Power Range Neutron Flux Rate-High Positive Rate	Existing NOTE - Bypass Test Time from 4 hours to 12 hours
		Required Action D revised to extend time before placing in tripped condition from 6 hours to 72 hours (and to extend time to be in Mode 3 from 12 hours to 78 hours) and is revised and restructured to reduce potential for confusion.
Condition E	• Power Range Neutron Flux - Low • Overtemperature Delta-T • Overpower Delta-T • Pressurizer Pressure - High • Steam Generator (SG) Water Level - Low Low	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours.
		Required Action E.1: Place channel in trip changed from 6 hours to 72 hours
		Required Action E.2: Be in Mode 3 changed from 12 hours to 78 hours
Condition F	• Intermediate Range Neutron Flux	Required Action F.1: Reduce thermal power to < P-6 changed from 2 hours to 24 hours
		Required Action F.2: Increase thermal power to > P-10 changed from 2 hours to 24 hours
Condition M	• Pressurizer Pressure - Low • Pressurizer Water Level - High • Reactor Coolant Flow - Low: Two Loops • Undervoltage RCPs • Underfrequency RCPs	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours.
		Required Action M.1: Place channel in trip changed from 6 hours to 72 hours
		Required Action M.2: Reduce thermal power to < P-7 changed from 12 hours to 78 hours
Condition N	• Reactor Coolant Flow - Low: Single Loop	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours.
		Required Action N.1: Place channel in trip changed from 6 hours to 72 hours
		Required Action N.2: Reduce thermal power to < P-8 changed from 10 hours to 76 hours
Condition O	• Turbine Trip - Low Fluid Oil Pressure	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours.
		Required Action O.1: Place channel in trip changed from 6 hours to 72 hours
		Required Action O.2: Reduce thermal power to < P-8 changed from 10 hours to 76 hours

Condition P	• Turbine Trip - Turbine Stop Valve Closure	Required Action P.1: Place channel in trip changed from 6 hours to 72 hours Required Action P.2: Reduce thermal power to < P-8 changed from 10 hours to 76 hours
Condition Q	• Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS) • Automatic Trip Logic (Modes 1 and 2)	Required Action Q.1: Restore train to OPERABLE status changed from 6 hours to 24 hours Required Action Q.2: Be in Mode 3 changed from 12 hours to 30 hours
Condition R	• Reactor Trip Breakers	Note 1: One train bypass time from 2 to 4 hours Note 2: One RTB bypass time deleted Required Action R.1: Restore train to OPERABLE status changed from 1 hr to 24 hours Required Action R.2: Be in Mode 3 changed from 7 hrs to 30 hrs
SR 3.3.1.4	• Reactor Trip Breakers • Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	TADOT frequency changed from 31 days to 62 days on a staggered test basis.
SR 3.3.1.5	• Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS) • Low Power Reactor Trips Block, P-7 • Automatic Trip Logic	Actuation Logic Test frequency changed from 31 days to 92 days on a staggered test basis.
SR 3.3.1.7	• Power Range Neutron Flux - High • Power Range Neutron Flux Rate - High Positive Rate • Source Range Neutron Flux (Modes 3, 4, & 5) • Overtemperature Delta-T • Overpower Delta-T • Pressurizer Pressure o Low o High • Pressurizer Water Level - High • Reactor Coolant Flow - Low o Single Loop o Two Loops • Steam Generator (SG) Water Level - Low Low	Channel Operational Test frequency changed from 92 days to 184 days.
SR 3.3.1.8	• Power Range Neutron Flux - Low • Intermediate Range Neutron Flux • Source Range Neutron Flux (Mode 2)	Note that states "Only required when not performed within previous 92 days", frequency changed from 92 days to 184 days. Channel Operational Test frequency changed from 92 days to 184 days.

LCO 3.3.2, ESFAS Instrumentation		
Affected Condition	**Affected Instrumentation**	**Proposed Change**
Condition C	• Automatic Actuation Logic and Actuation Relays o Safety Injection o Containment Spray o Containment Isolation - Phase A o Containment Isolation - Phase B	Required Action C.1: Restore train to OPERABLE status changed from 6 hours to 24 hours Required Action C.2.1: Be in Mode 3 changed from 12 hours to 30 hours Required Action C.2.2: Be in Mode 5 changed from 42 hours to 60 hours
Condition D	• Safety Injection o Containment Pressure - High o Pressurizer Pressure - Low Low • Steam Line Isolation o Steam Line Pressure - Low o Steam Line Pressure - Negative Rate High • Feedwater Isolation o SG Water Level - High High (P-14) • Auxiliary Feedwater o SG Water Level - Low Low o Station Blackout ▪ Loss of Voltage ▪ Degraded Voltage	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours. Required Action D.1: Place channel in trip changed from 6 hours to 72 hours Required Action D.2.1: Be in Mode 3 changed from 12 hours to 78 hours Required Action D.2.2: Be in Mode 4 changed from 18 hours to 84 hours
Condition E	• Containment Spray o Containment Pressure - High High • Containment Isolation - Phase B o Containment Pressure - High High • Steam Line Isolation o Containment Pressure - High High	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours. Required Action E.1: Place channel in bypass changed from 6 hours to 72 hours Required Action E.2.1: Be in Mode 3 changed from 12 hours to 78 hours Required Action E.2.2: Be in Mode 4 changed from 18 hours to 84 hours
Condition H	• Automatic Actuation Logic and Actuation Relays o Steam Line Isolation o Feedwater Isolation o Auxiliary Feedwater	Required Action H.1: Restore train to OPERABLE status changed from 6 hours to 24 hours Required Action H.2.1: Be in Mode 3 changed from 12 hours to 30 hours Required Action H.2.2: Be in Mode 4 changed from 18 hours to 36 hours

Condition I	• Turbine Trip o Automatic Actuation Logic and Actuation Relays	Required Action I.1: Restore train to OPERABLE status changed from 6 hours to 24 hours Required Action I.2: Be in Mode 3 changed from 12 hours to 30 hours
Condition J	• Turbine Trip and Feedwater Isolation o Turbine Trip - SG Water Level - High High (P-14) o Feedwater Isolation - Tavg - Low coincident with Reactor Trip, P-4	Existing NOTE - Bypass Test Time changed from 4 hours to 12 hours. Required Action J.1: Place channel in trip changed from 6 hours to 72 hours Required Action J.2: Be in Mode 3 changed from 12 hours to 78 hours
SR 3.3.2.2	• Automatic Actuation Logic and Actuation Relays o Safety Injection o Containment Spray o Containment Isolation - Phase A o Containment Isolation - Phase B o Steam Line Isolation o Turbine Trip and Feedwater Isolation o Auxiliary Feedwater • Turbine Trip and Feedwater Isolation - SG Water Level - High High (P-14)	Actuation Logic Test frequency changed from 31 days to 92 days on a staggered test basis.
SR 3.3.2.4	• Automatic Actuation Logic and Actuation Relays o Safety Injection o Containment Spray o Containment Isolation - Phase A o Containment Isolation - Phase B o Steam Line Isolation o Turbine Trip and Feedwater Isolation o Auxiliary Feedwater • Turbine Trip and Feedwater Isolation - SG Water Level - High High (P-14)	Master Relay Test frequency changed from 31 days to 92 days on a staggered test basis.

SR 3.3.2.5	• Safety Injection o Containment Pressure - High o Pressurizer Pressure - Low Low • Containment Spray o Containment Pressure - High High • Containment Isolation - Phase B o Containment Pressure - High High • Steam Line Isolation o Containment Pressure - High High o Steam Line Pressure - Low o Steam Line Pressure Negative Rate - High • Turbine Trip and Feedwater Isolation o SG Water Level - High High (P-14) o Feedwater Isolation - Tave - Low coincident with reactor trip, P-4 • Auxiliary Feedwater o SG Water Level - Low Low • ESFAS Interlocks o Pressurizer Pressure, P-11 o Tave - Low Low, P-12	Channel Operational Test frequency changed from 92 days to 184 days.

The TS Bases related to the above changes were revised accordingly to support the discussions of the above changes. These proposed changes are consistent with TSTF-411, Revision 1 and TSTF-418, Revision 2. In addition:

1) Clarifying changes are being proposed to the Bases for LCO 3.3.2 for Catawba and McGuire. These changes apply to Conditions C, H, and I and clarify that the failure of an individual SSPS slave relay or slave relay contact to actuate does not render the associated SSPS train inoperable.

2) Clarifying changes are being proposed to the Bases for LCO 3.3.1 and LCO 3.3.2 for McGuire only. These changes apply to SRs 3.3.1.10 and 3.3.2.8 and clarify that the channel calibration may be performed at power or during refueling based on bypass testing capability. Catawba does not have permanently installed bypass testing capability; therefore, this Bases clarification is not applicable to Catawba.

The following is a list of differences from TSTF-418, Revision 2. These differences are due to plant specific design differences.

1. TS 3.3.1, Condition D is revised and restructured to avoid confusion as to when a flux map for QPTR is required. The revised Condition D captures the approved changes (bypass time of 12 hours, maintenance time before tripping of 72 hours), while eliminating QPTR and formatting confusions.
2. For TS 3.3.1, Condition K of TSTF-418 is Condition L for Catawba and Condition M for McGuire.
3. For TS 3.3.1, Catawba and McGuire have a separate Condition for Function 10.a, Reactor Coolant Flow - Low, Single Loop. This is Condition M for Catawba and Condition N for McGuire.
4. For TS 3.3.1, Catawba and McGuire do not have a reactor trip from reactor coolant pump breaker position. Therefore, Insert 3A from TSTF-418 was not used and the conditions for TS 3.3.1 were not relettered.
5. Catawba and McGuire have separate conditions (N & O for Catawba and O & P for McGuire) for each turbine trip function. The separate conditions were revised consistent with TSTF-418.
6. For TS 3.3.1, Condition O of TSTF-418 is Condition P for Catawba and Condition Q for McGuire.
7. For TS 3.3.2, Catawba and McGuire have an additional function of auxiliary feedwater start on loss of offsite power (Catawba) and station blackout (McGuire), which is governed by Condition D. This function is not addressed in TSTF-418 and was therefore addressed in plant specific analysis.
8. For TS 3.3.2, Catawba and McGuire have an additional Condition for main steam isolation individual steam line manual initiation. This is Condition G for Catawba and McGuire.
9. For TS 3.3.2 Condition G of TSTF-418 is Condition H for Catawba and McGuire.
10. For TS 3.3.2, Condition H of TSTF-418 is Condition I for Catawba and McGuire.
11. For TS 3.3.2, Condition I of TSTF-418 is Condition J for Catawba and McGuire.
12. For Catawba and McGuire, plant specific analysis for refueling water storage tank automatic switchover and loss of power diesel generator start instrumentation (TS 3.3.5), were not performed so these functions are not being revised by this TS amendment. Except as noted above, no other plant specific functions were evaluated for this TS amendment.

The following is a list of differences from TSTF-411, Revision 1. These differences are due to plant specific design differences.

1. For TS 3.3.1, Condition O of TSTF-411 is Condition Q for Catawba and Condition R for McGuire.
2. TS 3.3.6 in TSTF-411 Revision 1 is titled "Containment Purge and Exhaust Isolation Instrumentation." At McGuire, TS 3.3.6 was deleted under TS Amendment 243/224 approved by the NRC on July 26, 2007. At Catawba, TS 3.3.6 was modified under TS Amendment 196/189 approved by the NRC on March 20, 2002. This TS Amendment excluded the containment purge ventilation system and hydrogen purge system containment isolation valves from the instrumentation testing requirements in TS 3.3.6. The change left the Containment Air Release and Addition System requirements in TS 3.3.6 and revised the title of TS 3.3.6 to "Containment Air Release and Addition Isolation Instrumentation."
3. TSTF-411 Revision 1 revises TS 3.3.7 for the CREFS Actuation Instrumentation. Catawba and McGuire do not have this instrumentation in their respective TS.
4. Catawba has a boron dilution mitigation system (BDMS) installed while McGuire does not have BDMS installed. Therefore, Catawba includes TS 3.3.9 of TSTF-411 and McGuire does not.

These improvements will allow additional time to perform maintenance and test activities, enhance safety, provide additional operational flexibility, and reduce the potential for forced outages related to compliance with the RTS and ESFAS instrumentation Technical Specifications. Industry information has shown that a significant number of trips that have occurred are related to instrumentation test and maintenance activities, indicating that these activities should be completed with caution and sufficient time should be available to complete these activities in an orderly and effective manner.

3.0 BACKGROUND

The Westinghouse Owners Group Technical Specification Optimization Program (WOG TOPS) evaluated changes to surveillance test intervals and allowed outage times (AOTs) for the analog channels, logic cabinets, master and slave relays, and reactor trip breakers as documented in WCAP-10271-P-A series of reports. The NRC approved increasing the surveillance test intervals (STI), bypass test times, and AOTs for the analog channels, as well as the AOTs for the logic cabinets, master relays, and slave relays. A probabilistic risk assessment approach was used in these analyses which included assessing the impact of the changes on signal availability and plant safety. The justification for the acceptability of the changes was the small impact the changes had on plant safety. It was also demonstrated that increasing the surveillance test intervals for the analog channels leads to a decrease in inadvertent reactor trips since fewer test activities will be performed with a channel in trip. This provides a safety benefit.

The approach used in this program and presented in WCAP-14333-P-A Revision 1 (hereafter referred to as WCAP-14333) and WCAP-15376-P-A Revision 1 (hereafter referred to as WCAP-15376) is consistent with the approach established by WOG TOPS. This includes the fault tree models, signals, component reliability database, and most of the test and maintenance assumptions. Several changes in modeling were implemented to enhance the approach or to remove unnecessary conservatisms, such as, the common cause modeling approach for analog channels and the frequency of maintenance activities. The plant specific model used for the risk analysis was also changed. Differences in analysis methods from the TOPS WCAP-10271-P-A (hereafter referred to as WCAP-10271) series of reports are discussed in Section 7.1 of WCAP-14333 and in Section 8.3.5 of WCAP-15376. Catawba (references 8 & 9) and McGuire (references 10 & 11) both submitted TS changes to the NRC based on this program and WCAP-10271 and received NRC approval for those changes.

Important to understanding the analysis and approach is a basic understanding of the RTS and ESFAS designs, and also the performance of test and maintenance activities on these systems. This information is contained in WCAP-14333.

WCAP-14333 provides the justification for increasing the bypass times for testing and the Completion Times in the Reactor Protection System (RPS) instrumentation and Engineered Safety Features Actuation System (ESFAS) instrumentation Technical Specifications. The NRC issued a Safety Evaluation on July 15, 1998 approving WCAP-14333.

These improvements will allow additional time to perform maintenance and test activities, enhance safety, provide additional operational flexibility, and reduce the potential for forced outages related to compliance with the RTS and ESFAS instrumentation Technical Specifications. Industry information has shown that a significant number of trips that have occurred are related to instrumentation test and maintenance activities, indicating that these activities should be completed with caution and sufficient time should be available to complete these activities in an orderly and effective manner. These changes have been incorporated in Technical Specification Task Force (TSTF) traveler, TSTF-418, Revision 2, "RPS and ESFAS Test Times and Completion Times" (WCAP-14333).

WCAP-15376-P, Rev. 0, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," provides the justification for the following changes to the Improved Standard Technical Specifications for the Reactor Trip System (RTS) Instrumentation (3.3.1) and Engineered Safety Features Actuation System (ESFAS) Instrumentation (3.3.2):

1. Increase the Completion Time and the bypass test time for the reactor trip breakers.

2. Increase the Surveillance Test Intervals (STI) for the reactor trip breakers, master relays, logic cabinets, and analog channels.

The evaluation in WCAP-15376 considers both the Solid State Protection System and the Relay Protection System.

Depending on the plant protection system design, some of the actuation logic and master relays associated with the Containment Purge and Exhaust Isolation Instrumentation (3.3.6) Technical Specifications may be processed through the Relay or Solid State Protection System. Since the STIs for the actuation logic and master relays of the ESFAS Instrumentation were justified to be relaxed in this report, these STI relaxations are also applicable to the actuation logic and master relays for all signals processed through the Relay or Solid State Protection System.

The STI for the source range neutron flux CHANNEL OPERATIONAL TEST (COT) in the RTS Instrumentation (3.3.1) Technical Specification was justified to be relaxed in this report. Since this source range neutron flux channel is also used for the Boron Dilution Protection System (BDPS) in Technical Specification 3.3.9, the STI relaxation is also applicable to that STI. These changes have been incorporated in TSTF traveler, TSTF-411, Revision 1, "Surveillance Test Interval Extensions for Components of the Reactor Protection System" (WCAP-15376).

The implementation guidelines for WCAP-15376 (Reference 21) recommend that plants consider implementing WCAP-14333 when implementing WCAP-15376. The implementation guidelines for each WCAP (Reference 4) include Table 2, "Applicability of Analysis Reactor Trip Actuation Signals," and Table 3, "Applicability of Analysis Engineered Safety Features Actuation Signals." These Tables are the same for both WCAPs and therefore, will only be completed once for Catawba (Tables 3 and 4 of Attachment 6A) and McGuire (Tables 3 and 4 of Attachment 7A). Also, since both WCAPs will be implemented together, only one Note will be contained in the Required Action for the Condition for "One RTB train inoperable" of TS 3.3.1, as identified in TSTF-411, Revision 1.

Condition F of TS 3.3.1 applies when THERMAL POWER is between the P-6 and P-10 interlock setpoints and one intermediate range channel is inoperable. The Completion Time associated with this Condition permits 2 hours to exit this power interval. NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors," Revision 5, Action 3b of Table 3.3-1 allowed one Intermediate Range Neutron Flux channel to be inoperable for an indefinite period of time with power level above the P-6 (Intermediate Range Neutron Flux Interlock) but below 10% of RATED THERMAL POWER. The inoperable channel was required to be restored to OPERABLE status prior to increasing power above 10%. During the development of the NUREG, the justification for changing this action to the NUREG-1431 Condition F did not describe or provide any justification for the 2 hours.

TSTF-246, "RTS Instrumentation, 3.3.1 Condition F Completion Time," increases the Completion Times for Condition F.1 and F.2 from 2 hours to 24 hours. This TSTF was approved by the NRC on March 22, 1999.

4.0 TECHNICAL ANALYSIS

The Westinghouse Owners Group Technical Specification Optimization Program (WOG TOPS) evaluated changes to surveillance test intervals and allowed outage times for the analog channels, logic cabinets, master and slave relays, and reactor trip breakers. The NRC approved increasing the surveillance test intervals (STI), bypass test times, and AOTs for the analog channels, as well as the AOTs for the logic cabinets, master relays, and slave relays. A probabilistic risk assessment (PRA) approach was used in these analyses which included assessing the impact of the changes on signal availability and plant safety. The justification for the acceptability of the changes was the small impact the changes had on plant safety. It was also demonstrated that increasing the surveillance test intervals for the analog channels leads to a decrease in inadvertent reactor trips since fewer test activities will be performed with a channel in trip. This provides a safety benefit.

The approach used in this program and presented in WCAP-14333 is consistent with the approach established by WOG TOPS. This includes the fault tree models, signals, component reliability database, and most of the test and maintenance assumptions. Several changes in modeling were implemented to enhance the approach or to remove unnecessary conservatisms, such as, the common cause modeling approach for analog channels and the frequency of maintenance activities. The plant specific model used for the risk analysis was also changed. The WOG TOPS work used the Indian Point Unit 2 and the Millstone Unit 3 models that were available in the early 1980s. The work done in WCAP-14333 uses a plant specific PRA model that was completed to meet the Individual Plant Examination requirement (Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities").

Important to understanding the analysis and approach is a basic understanding of the RTS and ESFAS designs, and also the performance of test and maintenance activities on these systems. This information is contained in WCAP-14333.

A survey was provided to all WOG members to determine their needs with respect to instrumentation test times, maintenance times, and maintenance frequencies, in addition to information regarding plant operation, such as, reactor trip and spurious safety injection events. From this information the Technical Specification changes that were evaluated were identified. The probabilistic risk analysis, benefits of the program and conclusions, and the relationship of the Technical Specification changes to the analysis are discussed in WCAP-14333 and WCAP-15376.

To model these Completion Times in the fault trees to determine the impact of the changes on signal unavailabilities, several parameters were specified for component test and maintenance unavailabilities. These are the test and maintenance frequencies, and the time to complete the test and maintenance activities. These are discussed in more detail in WCAP-14333 and WCAP-15376.

The changes being considered in this analysis were evaluated consistent with the three tiered approach currently defined in Regulatory Guide 1.177. The first tier addresses PRA insights and includes the risk analyses and sensitivity analyses to support the completion time and bypass test time changes. The second tier addresses avoidance of risk-significant plant configurations. The third tier addresses risk-informed plant configuration control and management.

The approach used in WCAP-15376 is consistent with the Nuclear Regulatory Commission's (NRC) approach for using probabilistic risk assessment in risk-informed decisions on plant-specific changes to the current licensing basis as presented in Regulatory Guides 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Current Licensing Basis," and 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications." The approach addresses, as documented in this report, the impact on defense-in-depth and the impact on safety margins, as well as an evaluation of the impact on risk. The risk evaluation considers the three-tiered approach as presented by the NRC in Regulatory Guide 1.177 for the extension to the RTB Completion Time. Tier 1, PRA Capability and Insights, assesses the impact of the proposed Completion Time (AOT) change on core damage frequency (CDF), incremental conditional core damage probability (ICCDP), large early release frequency (LERF), and incremental conditional large early release probability (ICLERP). Tier 2, Avoidance of Risk- Significant Plant Configurations, and Tier 3, Risk-Informed Plant Configuration Control and Management, are addressed on a plant specific basis for both the Catawba and McGuire Nuclear Stations.

Safety Evaluation (SE) Conditions

NRC approval of WCAP-14333 was subject to the following conditions requiring plant-specific information:

1. Confirm the applicability of the WCAP-14333 analyses for the plant.

2. Address the Tier 2 and 3 analyses including the Configuration Risk Management Program (CRMP) insights which confirm that these insights are incorporated into the decision making process before taking equipment out of service.

NRC approval of WCAP-15376 was subject to the following conditions requiring plant-specific information:

1. Confirm the applicability of the topical report to the plant and perform a plant-specific assessment of containment failures and address any design or performance differences that may affect the proposed changes.

2. Address the Tier 2 and Tier 3 analyses including risk significant configuration insights and confirm that these insights are incorporated into the plant-specific configuration risk management program.

3. The risk impact of concurrent testing of one logic cabinet and associated reactor trip breaker needs to be evaluated on a plant-specific basis to ensure conformance with the WCAP-15376, and Regulatory Guides 1.174 and 1.177.

4. To ensure consistency with the reference plant, the model assumptions for human reliability in WCAP-15376 should be confirmed to be applicable to the plant specific configuration.

5. For future digital upgrades with increased scope, integration and architectural differences beyond that of Eagle 21, the staff finds the generic applicability of WCAP-15376 to future digital systems not clear and should be considered on a plant-specific basis.

6. An additional commitment from the response to NRC RAI Question 18 (Reference 10) requires that each plant will review their setpoint calculation methodology to ascertain the impact of extending the Channel Operational Test (COT) Surveillance Frequency from 92 days to 184 days.

Duke Response to NRC Condition and Limitation 1 for WCAP-14333 and WCAP-15376

In order to address NRC Condition and Limitation 1 for both WCAPs, Westinghouse issued implementation guidelines for licensees (References 4, 21, & 22) to confirm the analyses are applicable to their plant. See Attachments 6 and 7.

Duke Response to NRC Condition and Limitation 2 for WCAP-14333 and WCAP-15376

The Tier 2 requirements of RG 1.177 state that the licensee should provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when specific plant equipment is out of service consistent with the proposed TS change. Tier 2 identifies and evaluates any potential risk-significant plant equipment outage configurations associated with the proposed change and provides reasonable assurance that risk-significant plant equipment outage configurations will not occur when equipment associated with the proposed TS change is out-of-service.

The Tier 3 requirements of RG 1.177 require the licensee to develop a program that ensures that the risk impact of out-of-service equipment is appropriately evaluated prior to performing any maintenance activity. Tier 3 provides for the establishment of an overall Configuration Risk Management Program (CRMP) and confirmation that its insights are incorporated into the decision-making process before taking equipment out-of-service prior to or during the completion time. Tier 3 provides additional coverage on the basis of any additional risk-significant configurations that may be encountered during maintenance scheduling over extended periods of plant operation. Tier 3 guidance is satisfied by 10 CFR 50.65(a)(4) which requires a licensee to assess and manage the increase in risk that may result from activities such as surveillance, testing, and corrective and preventive maintenance.

The Tier 2 and Tier 3 requirements of RG 1.177 have been addressed at Duke for McGuire/Catawba as indicated below.

Tier 2 Assessment: Risk-significant Plant Equipment Outage Configurations

WCAP-15376

WCAP-15376 provides the following Tier 2 insights which are applicable to the proposed STI extension at McGuire/Catawba:

- Activities that degrade the availability of auxiliary feedwater, reactor coolant system (RCS) pressure relief, ATWS mitigating system actuation circuitry (AMSAC), or turbine trip should not be scheduled when an RTB is out of service.

- Activities that could degrade the operable train of RPS including master relays, slave relays, and analog channels should not be scheduled concurrently with the out of service train.

- Activities on electrical support systems for auxiliary feedwater, RCS pressure relief, AMSAC, or turbine trip should not be scheduled during RTB maintenance.

COMMITMENT: As part of the implementation of the proposed license amendment, Duke will implement administrative controls in the McGuire/Catawba Maintenance Rule 10 CFR 50.65(a)(4) program to include the above restrictions when an RTB and/or logic cabinet is removed from service.

WCAP-14333

WCAP-14333 provides the following Tier 2 insights which are applicable to the proposed STI extension at McGuire/Catawba:

- In the case of a logic cabinet in maintenance, several systems had a relatively significant increase in rank of importance, including auxiliary feedwater, reactor trip, high pressure injection, containment cooling, and low pressure injection.

COMMITMENT: As part of the implementation of the proposed license amendment, to address a logic cabinet in maintenance, Duke will ensure solid state protection system (SSPS) train and engineered safety features actuation system (ESFAS) train unavailability is included in the McGuire/Catawba Maintenance Rule 10 CFR 50.65(a)(4) program.

Tier 3 Assessment: Maintenance Rule Configuration Control

10 CFR 50.65 (a)(4), RG 1.182, and NUMARC 93-01 require that prior to performing maintenance activities, risk assessments shall be performed to assess and manage the increase in risk that may result from proposed maintenance activities. These requirements are applicable for all plant modes. NUMARC 91-06 requires utilities to assess and manage the risks that occur during the performance of outages.

Duke has several Work Process Manual procedures and Nuclear System Directives that are in place at McGuire/Catawba to ensure the requirements of the Maintenance Rule are implemented. These procedures and directives are used to address the Maintenance Rule requirement and the on-line (and off-line) Maintenance Policy requirement to control the safety impact of combinations of equipment removed from service. They assure that the risk associated with the various plant configurations planned during at-power or shutdown conditions is assessed prior to entry into these configurations and is appropriately managed while the plant is in these various configurations. More specifically, the Nuclear System Directives address the process, define the program, and state individual group responsibilities to ensure compliance with the Maintenance Rule. The Work Process Manual procedures provide a consistent process for utilizing the computerized software assessment tool which manages the risk associated with equipment inoperability.

The electronic risk assessment tool is utilized by plant personnel to analyze and manage the risk associated with all risk significant work activities including assessment of combinations of equipment removed from service. It is independent of the requirements of Technical Specifications and Selected Licensee Commitments.

The electronic risk assessment tool models for McGuire/Catawba are based on a "blended" approach of probabilistic (the full at-power PRA models are utilized) and traditional deterministic approaches. The results of the risk assessment include a prioritized listing of equipment to return to service, a prioritized listing of equipment to remain in service, and potential contingency considerations.

Additionally, prior to the release of work for execution, Operations personnel must consider the effects of severe weather and grid instabilities on plant operation. This qualitative evaluation is inherent of the duties of the Work Control Center Senior Reactor Operator (SRO). Responses to actual plant risk due to severe weather or grid instabilities are programmatically incorporated into applicable plant emergency or response procedures.

The ESFAS and RPS systems are currently included in the Maintenance Rule Program, and as such, availability and reliability performance criteria have been established to assure they perform adequately.

Duke Response to NRC Condition and Limitation 3 for WCAP-15376

This condition and limitation is addressed in Attachments 6 and 7 for Catawba and McGuire.

Duke Response to NRC Condition and Limitation 4 for WCAP-15376

This condition and limitation is addressed in Attachments 6 and 7 for Catawba and McGuire.

Duke Response to NRC Condition and Limitation 5 for WCAP-15376

This condition and limitation does not apply to Catawba and McGuire at this time. Future digital upgrades will require separate evaluation.

Duke Response to NRC Condition and Limitation 6 for WCAP-15376 (RAI Question #18 Commitment)

The response to this RAI (reference 19) noted that plant-specific RTS and ESFAS setpoint uncertainty calculations and assumptions, including instrument drift, will be reviewed to determine the impact of extending the Surveillance Frequency of the COT from 92 days to 184 days.

The rack drift term used in the CNS and MNS setpoint studies is based on the 92 day interval for COTs. Therefore, an increase to the COT Frequency from 92 days to 184 days will be verified to have no impact on the setpoint study. As a part of the TS license amendment request to change from monthly to quarterly COT surveillance interval increases in Reference 8 (CNS) and Reference 10 (MNS), personnel reviewed as-found and as-left data.

In conjunction with Reference 8, Catawba Engineering personnel reviewed "as found" and "as left" data for the RTS and ESFAS setpoints for a 12-month period and concluded that sufficient margin is present to offset the drift anticipated as a result of quarterly surveillance. The allowable margin present in the setpoints is more than adequate to offset any drift observed based upon review of the data.

In conjunction with Reference 10, McGuire Engineering personnel reviewed "as found" and "as left" data for the RTS and ESFAS setpoints for a 16-month period for Unit 1 and a 14-month period for Unit 2 and concluded that sufficient margin is present to offset the drift anticipated as a result of quarterly surveillance.

While Duke does not anticipate any impact in going from 92 days to 184 days, CNS and MNS will trend "as found" and "as left" data under the System Health Program for the three representative trip functions analyzed in WCAP-15376 (i.e., OTDT, SG level, and pressurizer pressure) for two years (four data points) after implementation of the amendment granting 184-day COTs.

Deviations from approved TSTF-411 Revision 1 and TSTF-418 Revision 2

In addition to the discussions in section 2 of this Enclosure, the following additional information is provided.

TS 3.3.1 Condition D is restructured to avoid confusion as to when a flux map for QPTR is required. The version of Condition D approved in TSTF-418 Revision 2 could incorrectly lead an operator to believe that he could pursue just the option of Required Actions D.1.1 and D.1.2, potentially overlooking the requirement to do a flux map for QPTR within 12 hours per the Note above SR 3.2.4.2. In addition, Required Actions with shorter Completion Times (12 hours) are supposed to appear before Required Actions with longer Completion Times (72 hours) in the D.2.1 and D.2.2 option. The revised Condition D captures the approved changes (bypass time of 12 hours, maintenance time before tripping of 72 hours), while eliminating the QPTR and formatting confusions. This proposed change is identical to that approved for Wolf Creek in Amendment 156 dated January 31, 2005 (ADAMS accession number ML050320254).

The changes in TSTF-418 Revision 2 regarding the TS 3.3.1 Condition for Reactor Trip Breakers are superseded by the changes in TSTF-411 Revision 1. Option 3 of Insert 6 in TSTF-411 Revision 1 is followed.

<u>Bypass Testing Capability</u>

The systems providing input signals to the SSPS (NIS and Process Control System (PCS)) incorporate system level testing provisions to allow on-line testing. The SSPS includes a Semi-Automatic tester and a Safeguards Test Cabinet for on-line testing of both the actuation logic in the SSPS and the connection to the actuated devices. The Reactor Trip Switchgear has additional provisions to allow on-line testing.

Originally, the protection system was designed to trip the channel under test, partially satisfying the 2/4 and 2/3 logic. This method is still in use at Catawba.

At McGuire, experience showed that this places the plant in a vulnerable condition, in that a transient-induced or technician-induced trip in any loop of any other channel would cause a reactor trip. McGuire has made a revision to the testing method for the PCS, reactor coolant pump monitor (RCPM), and NIS that allows the tested channel to be placed in "BYPASS", an untripped condition. Circuitry was added to the NIS Interposing Relay Cabinets to preclude having different channels of the PCS, RCPM, and NIS in "BYPASS" at the same time. This "BYPASS" capability has not been implemented at Catawba.

TSTF-246, Revision 0 Evaluation

This proposed change is acceptable for the following reasons: (a) adequate protection is still provided by the remaining intermediate range (IR) channel and the power range (PR) channels, (b) if the second IR channel is not available, Condition G would require no positive reactivity additions and reduction of power to below P-6 within 2 hours, and (c) the PR low setpoint is the safety analysis credited protection for power excursions between P-6 and P-10. If a PR low setpoint channel is not available, Condition E would require that channel to be placed in trip within 6 hours (or be in MODE 3 within 12 hours) thus fulfilling the safety function for that PR channel. Furthermore, with one PR low setpoint channel inoperable, the requirement to be in MODE 3 within 12 hours is less restrictive than the STS requirement to increase power to above P-10 in 2 hours.

In addition, a 2 hour Completion Time is impractical for increasing power above P-10 depending on plant conditions at the time one channel was determined inoperable. (For example, a main feedwater pump may be required to be in operation for reactor power to approach and increase above P-10, which in turn requires completion of main feedwater pump testing prior to it being placed in service.)

With the remaining IR and PR channels OPERABLE, the change from 2 hours to 24 hours is reasonable. If the remaining IR or any of the PR channels are inoperable, more restrictive action requirements apply. Therefore, a limit of 24 hours is conservative with respect to the previous version of Standard Technical Specifications, while providing a more reasonable time frame for accomplishing the required action (i.e., a slow and controlled power adjustment above P-10 or below P-6, as the STS Bases state).

Plant Specific Analysis for Auxiliary Feedwater Start on Loss of Offsite Power/Station Blackout

The acceptability of increasing the existing Completion Times for this function in Catawba and McGuire TS Table 3.3.2-1, Function 6d, as governed by Condition D, has been evaluated quantitatively using the Catawba and McGuire Revision 3a PRAs. The PRAs have determined that the proposed 12-hour bypass time and 72-hour completion time are justified. Based on a comparison of the calculated change in core damage frequency, change in large early release frequency, incremental conditional core damage probability, and incremental conditional large early release probability against Regulatory Guide 1.174 and 1.177 criteria, the calculated values determined from analysis were significantly less than the Regulatory Guide values. A summary of the results is shown below.

TS change	dCDF	ICCDP	dLERF	ICLERP
Trip: 6 to 72 hrs (Catawba)	1.3E-11/rx yr	1.5E-11	1.3E-12/rx yr	1.5E-12
Bypass: 4 to 12 hrs (Catawba)	7.9E-13/rx yr	1.2E-12	8.2E-14/rx yr	1.3E-13
Trip: 6 to 72 hrs (McGuire)	2.0E-11/rx yr	2.2E-11	2.1E-12/rx yr	2.3E-12
Bypass: 4 to 12 hrs (McGuire)	1.2E-12/rx yr	1.9E-12	1.3E-13/rx yr	2.0E-13

5.0 REGULATORY ANALYSIS

This section addresses the standards of 10 CFR 50.92 as well as the applicable regulatory requirements and acceptance criteria.

5.1 NO SIGNIFICANCE HAZARDS CONSIDERATIONS (NHSC)

The following discussion is a summary of the evaluation of the changes contained in this proposed amendment against the 10 CFR 50.92(c) requirements to demonstrate that all three standards are satisfied. A no significant hazards consideration is indicated if operation of the facility in accordance with the proposed amendment would not:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated, or

2. Create the possibility of a new or different kind of accident from any accident previously evaluated, or

3. Involve a significant reduction in a margin of safety.

First Standard

Does operation of the facility in accordance with the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed changes to the Completion Times, bypass test time, and Surveillance Frequencies reduces the potential for inadvertent reactor trips and spurious actuations, and therefore do not increase the probability of any accident previously evaluated. The proposed changes to the Completion Times and bypass test time do not change the response of the plant to any accidents and have an insignificant impact on the reliability of the reactor trip system and engineered safety feature actuation system (RTS and ESFAS) signals. The RTS and ESFAS will remain highly reliable and the proposed changes will not result in a significant increase in the risk of plant operation. This is demonstrated by showing that the impact on plant safety as measured by core damage frequency (CDF) is less than 1.0E-06 per year and the impact on large early release frequency (LERF) is less than 1.0E-07 per year. In addition, for the Completion Time change, the incremental conditional core damage probabilities (ICCDP) and incremental conditional large early release probabilities (ICLERP) are less than 5.0E-07 and 5.0E-08, respectively. These changes meet the acceptance criteria in Regulatory Guides 1.174 and 1.177. Therefore, since the RTS and ESFAS will continue to perform their functions with high reliability as originally assumed, and the increase in risk as measured by CDF, LERF, ICCDP, and ICLERP is within the acceptance criteria of existing regulatory guidance, there will not be a significant increase in the consequences of any accidents.

The proposed changes do not adversely affect accident initiators or precursors nor alter the design assumptions, conditions, or configuration of the facility or the manner in which the plant is operated and maintained. The proposed changes do not alter or prevent the ability of structures, systems, and components (SSCs) from performing their intended function to mitigate the consequences of an initiating event within the assumed acceptance limits. The proposed changes do not affect the source term, containment isolation, or radiological release assumptions used in evaluating the radiological consequences of an accident previously evaluated. Further, the proposed changes do not increase the types or amounts of radioactive effluent that may be released offsite, nor significantly increase individual or cumulative occupational/public radiation exposures. The proposed changes are consistent with safety analysis assumptions and resultant consequences.

The determination that the results of the proposed changes are acceptable was established in the NRC Safety Evaluations prepared for WCAP-14333-P-A (issued by letter dated July 15, 1998) and for WCAP-15376-P-A (issued by letter dated December 20, 2002). Implementation of the proposed changes will result in an insignificant risk impact. Applicability of these conclusions has been verified through plant-specific reviews and implementation of the generic analysis results in accordance with the respective NRC Safety Evaluation conditions.

The proposed changes based on TSTF-246 do not involve any physical alteration of plant systems, structures, or components. The remaining intermediate range and power range nuclear instruments remain operable and have required actions that ensure compliance with applicable safety analyses.

Therefore, it is concluded that this change does not increase the probability of occurrence of a malfunction of equipment important to safety.

Second Standard

Does operation of the facility in accordance with the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The proposed changes do not result in a change in the manner in which the RTS or ESFAS provide plant protection. The RTS and ESFAS will continue to have the same setpoints after the proposed changes are implemented. There are no design changes associated with the license amendment. The changes to Completion Times, bypass test times, and Surveillance Frequencies do not change any existing accident scenarios, nor create any new or different accident scenarios. The changes do not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed) or a change in the methods governing normal plant operation. In addition, the changes do not alter assumptions made in the safety analysis. The proposed changes are consistent with the safety analysis assumptions and current plant operating practice.

The proposed changes do not introduce new failure mechanisms for systems, structures, or components not already considered in the UFSAR. Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created because no new failure mechanisms or initiating events have been introduced.

Third Standard

Does operation of the facility in accordance with the proposed amendment involve a significant reduction in the margin of safety?

Response: No.

The proposed changes do not alter the manner in which safety limits, limiting safety system settings, or limiting conditions for operation are determined. The safety analysis acceptance criteria are not impacted by these changes.

Redundant RTS and ESFAS trains are maintained, and diversity with regard to the signals that provide reactor trip and ESFAS is also maintained. Signals credited as primary or secondary and operator actions credited in the accident analyses will remain the same. The proposed changes will not result in plant operation in a configuration outside design basis. The calculated impact on risk is insignificant and meets the acceptance criteria contained in Regulatory Guides 1.174 and 1.177. Although there was no attempt to quantify any positive human factors benefit due to increased Completion Times and bypass test time, it is expected that there would be a net benefit due to a reduced potential for spurious reactor trips and actuations associated with testing.

Implementation of the proposed changes is expected to result in an overall improvement in safety, as follows:

a. Reduced testing will result in fewer inadvertent reactor trips, less frequent actuation of ESFAS components, less frequent distraction of operations personnel without significantly affecting RTS and ESFAS reliability.

b. Improvements in the effectiveness of the operating staff in monitoring and controlling plant operation will be realized. This is due to less frequent distraction of the operators and shift supervisor to attend to instrumentation Required Actions with short Completion Times.

c. Longer repair times associated with increased Completion Times will lead to higher quality repairs and improved reliability.

d. The Completion Time extensions for the reactor trip breakers will provide the utilities additional time to complete test and maintenance activities while at power, potentially reducing the number of forced outages related to compliance with reactor trip breaker Completion Times, and provide consistency with the Completion Times for the logic trains.

Therefore, it is concluded that this change does not involve a significant reduction in the margin of safety.

Based upon the preceding discussion, Duke has concluded that the proposed amendment does not involve a significant hazards consideration.

5.2 APPLICABLE REGULATORY REQUIREMENTS/CRITERIA

The regulatory bases and guidance documents associated with the systems discussed in this application include:

GDC-2 requires that structures, systems, and components important to safety be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without the loss of capability to perform their safety functions.

GDC-4 requires that structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

GDC-13 requires that instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems.

GDC-20 requires that the protection system(s) shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

GDC-21 requires that the protection system(s) shall be designed for high functional reliability and testability.

GDC-22 through GDC-25 and GDC-29 require various design attributes for the protection system(s), including independence, safe failure modes, separation from control systems, requirements for reactivity control malfunctions, and protection against anticipated operational occurrences.

Regulatory Guide 1.22 discusses an acceptable method of satisfying GDC-20 and GDC-21 regarding the periodic testing of protection system actuation functions. These periodic tests should duplicate, as closely as practicable, the performance that is required of the actuation devices in the event of an accident.

10CFR50.55a(h) requires that the protection systems meet IEEE 279-1971. Sections 4.9 - 4.11 of IEEE 279-1971 discuss testing provisions for protection systems.

There will be no changes to the RTS or ESFAS instrumentation design such that compliance with any of the regulatory requirements and guidance documents above would come into question. The above evaluations confirm that the plant will continue to comply with applicable regulatory requirements.

Based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.22(b), an evaluation of this license amendment request has been performed to determine whether or not it meets the criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9) of the regulations.

Implementation of this amendment will have no adverse impact upon the Catawba or McGuire units; neither will it contribute to any additional quantity or type of effluent being available for adverse environmental impact or personnel exposure.

It has been determined there is:

1. No significant hazards consideration,

2. No significant change in the types, or significant increase in the amounts, of any effluents that may be released offsite, and

3. No significant increase in individual or cumulative occupational radiation exposures involved.

Therefore, this amendment to the Catawba and McGuire TS meets the criteria of 10 CFR 51.22(c)(9) for categorical exclusion from an environmental impact statement.

7.0 REFERENCES

1. Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis."
2. Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications."
3. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times."
4. Letter, K.J. Vavrek, Westinghouse, to Westinghouse Owners Group Licensing Subcommittee Representatives, "Implementation Guideline for WCAP-14333-P-A, Rev. 1 (Proprietary), "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times" (MUHP-3054)," dated December 2, 1998.
5. WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," March 2003.
6. Industry/TSTF Standard Technical Specification Change Traveler TSTF-411, Revision 1, "Surveillance Test Interval Extensions for Components of the Reactor Protection System (WCAP-15376)."
7. Industry/TSTF Standard Technical Specification Change Traveler TSTF-418, Revision 2, "RPS and ESFAS Test Times and Completion Times (WCAP-14333)."
8. Duke Letter from M. S. Tuckman to U.S. Nuclear Regulatory Commission dated January 25, 1993.
9. Letter from R. E. Martin, Project Manager - U.S. Regulatory Commission to D. L. Rehn dated July 19, 1994, Issuance of License Amendments 122 and 106 for Catawba.

10. Duke Letter from T. C. McMeekin to U.S. Nuclear Regulatory Commission dated January 13, 1995.

11. Letter from V. Nerses, Project Manager - U.S. Regulatory Commission to T. C. McMeekin dated February 19, 1996, Issuance of License Amendments 163 and 147 for McGuire.

12. WCAP-10271-P-A and Supplement 1-P-A, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," May 1986.

13. WCAP-10271-P-A Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," June 1990.

14. Southern Nuclear Operating Company letters LCV-1364 dated October 13, 1999 and LCV-1364-A dated June 1, 2000, Docket Numbers 50-424 and 50-425.

15. NRC Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants," May 2000.

16. NUMARC 93-01, Revision 3, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," July 2000.

17. NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," December 1991.

18. Letter from R. H. Bryan, Westinghouse Owners Group, to NRC Document Control Desk, "Transmittal of Response to Request for Additional Information (RAI) Numbers 4 and 11 Regarding WCAP-15376-P, Rev. 0, 'Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times' (MUHP-3046)," dated January 8, 2002. (Note: This letter is part of Appendix D of WCAP-15376-P-A.)

19. Letter from R. H. Bryan, Westinghouse Owners Group, to NRC Document Control Desk, "Transmittal of Response to Request for Additional Information (RAI) Regarding WCAP-15376-P, Rev. 0, 'Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times' (MUHP-3046)," dated September 28, 2001. (Note: This letter is part of Appendix D of WCAP-15376-P-A.)

20. Industry/TSTF Standard Technical Specification Change Traveler TSTF-246, Revision 0, "RTS Instrumentation, 3.3.1 Condition F Completion Time."

21. Letter, K.J. Vavrek, Westinghouse, to Westinghouse Owners Group Licensing Subcommittee Representatives, Transmittal of Approved Topical Report: WCAP-15376-P-A, Rev. 1, (Proprietary) "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times" and Implementation Guidelines (MUHP-3046). April 3, 2003.

22. Letter, K.J. Vavrek, Westinghouse, to Westinghouse Owners Group Licensing Subcommittee Representatives, Transmittal of Revised Implementation Guidelines for WCAP-15376-P-A, Rev. 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times" (MUHP-3046). May 6, 2004.

ATTACHMENT 1

MARKUP OF TECHNICAL SPECIFICATIONS PAGES FOR CATAWBA

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One channel inoperable.	-----------------NOTE----------------- The inoperable channel may be bypassed for up to 4 hours for surveillance testing and setpoint adjustment of other channels. --	
	D.1.1 Place channel in trip.	6 hours
	<u>AND</u>	
	D.1.2 Reduce THERMAL POWER to ≤ 75% RTP.	12 hours
	<u>OR</u>	
	D.2.1 Place channel in trip.	6 hours
	<u>AND</u>	
	D.2.2 ------------NOTE------------ Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. ------------------------------- Perform SR 3.2.4.2.	Once per 12 hours
	<u>OR</u>	
	D.3 Be in MODE 3.	12 hours

(continued)

INSERT

INSERTS

INSERT FOR CATAWBA TS 3.3.1, CONDITION D

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One channel inoperable.	-------------------NOTE------------------- The inoperable channel may be bypassed for up to 12 hours for surveillance testing and setpoint adjustment of other channels. ---	
	D.1.1 ------------NOTE------------- Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. ----------------------------------- Perform SR 3.2.4.2.	12 hours from discovery of THERMAL POWER > 75% RTP <u>AND</u> Once per 12 hours thereafter
	<u>AND</u>	
	D.1.2 Place channel in trip.	72 hours
	<u>OR</u>	
	D.2 Be in MODE 3.	78 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One channel inoperable.	-----------------NOTE----------------- The inoperable channel may be bypassed for up to ~~4~~ hours for 12 surveillance testing of other channels. ---	
	E.1 Place channel in trip.	72 ~~6~~ hours
	<u>OR</u>	
	E.2 Be in MODE 3.	78 ~~12~~ hours
F. THERMAL POWER > P-6 and < P-10, one Intermediate Range Neutron Flux channel inoperable.	F.1 Reduce THERMAL POWER to < P-6.	24 ~~2~~ hours
	<u>OR</u>	
	F.2 Increase THERMAL POWER to > P-10.	24 ~~2~~ hours
G. THERMAL POWER > P-6 and < P-10, two Intermediate Range Neutron Flux channels inoperable.	G.1 -------------NOTE------------- Limited boron concentration changes associated with RCS inventory control or limited plant temperature changes are allowed. ---------------------------------- Suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>	
	G.2 Reduce THERMAL POWER to < P-6.	2 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. One channel inoperable.	------------------NOTE------------------ The inoperable channel may be bypassed for up to 4 hours for 12 surveillance testing of other channels. --	
	L.1 Place channel in trip.	72 6 hours
	OR	
	L.2 Reduce THERMAL POWER to < P-7.	78 12 hours
M. One Reactor Coolant Flow - Low (Single Loop) channel inoperable.	------------------NOTE------------------ The inoperable channel may be bypassed for up to 4 hours for 12 surveillance testing of other channels. --	
	M.1 Place channel in trip.	72 6 hours
	OR	
	M.2 Reduce THERMAL POWER to < P-8.	76 10 hours
N. One Turbine Trip - Stop Valve EH Pressure Low channel inoperable.	------------------NOTE------------------ The inoperable channel may be bypassed for up to 4 hours for 12 surveillance testing of other channels. --	
	N.1 Place channel in trip.	72 6 hours
	OR	
	N.2 Reduce THERMAL POWER to < P-9.	76 10 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
O. One or more Turbine Trip - Turbine Stop Valve Closure channels inoperable.	O.1 Place channel(s) in trip. OR O.2 Reduce THERMAL POWER to < P-9.	72 ~~6~~ hours 76 ~~10~~ hours
P. One train inoperable.	-----------------NOTE----------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. -- P.1 Restore train to OPERABLE status. OR P.2 Be in MODE 3.	 24 ~~6~~ hours 30 ~~12~~ hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
Q. One RTB train inoperable.	----------NOTE~~S~~---------- ~~1.~~ One train may be bypassed for up to ~~2~~ 4 hours for surveillance testing, provided the other train is OPERABLE. ~~2. One RTB may be bypassed for up to 2 hours for maintenance on undervoltage or shunt trip mechanisms, provided the other train is OPERABLE.~~ --------------------------------	
	Q.1 Restore train to OPERABLE status.	~~1~~ 24 hours
	OR	
	Q.2 Be in MODE 3.	~~7~~ 30 hours
R. One or more channel(s) inoperable.	R.1 Verify interlock is in required state for existing unit conditions.	1 hour
	OR	
	R.2 Be in MODE 3.	7 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.4	------------NOTE------------ This Surveillance must be performed on the reactor trip bypass breaker prior to placing the bypass breaker in service. ---------------------------- Perform TADOT.	62 ~~31~~ days on a STAGGERED TEST BASIS
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	92 ~~31~~ days on a STAGGERED TEST BASIS
SR 3.3.1.6	------------NOTE------------ Not required to be performed until 24 hours after THERMAL POWER is $\geq$ 75% RTP. ---------------------------- Calibrate excore channels to agree with incore detector measurements.	92 EFPD
SR 3.3.1.7	------------NOTE------------ Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entry into MODE 3. ---------------------------- Perform COT.	184 ~~92~~ days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.8	---------------------------------NOTE--------------------------------- This Surveillance shall include verification that interlocks P-6 (for the Intermediate Range channels) and P-10 (for the Power Range channels) are in their required state for existing unit conditions. --- Perform COT.	---------NOTE------- Only required when not performed within previous ~~92~~ 184 days -------------------------- Prior to reactor startup <u>AND</u> Four hours after reducing power below P-10 for power and intermediate range instrumentation <u>AND</u> Four hours after reducing power below P-6 for source range instrumentation <u>AND</u> Every ~~92~~ 184 days thereafter

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train inoperable.	C.1 -------------NOTE-------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---------------------------------- Restore train to OPERABLE status.	~~6~~ 24 hours
	OR	
	C.2.1 Be in MODE 3.	~~12~~ 10 hours
	AND	
	C.2.2 Be in MODE 5.	~~42~~ 60 hours
D. One channel inoperable.	D.1 -------------NOTE-------------- The inoperable channel may be bypassed for up to 12 ~~4~~ hours for surveillance testing of other channels. ---------------------------------- Place channel in trip.	~~6~~ 72 hours
	OR	
	D.2.1 Be in MODE 3.	~~12~~ 78 hours
	AND	
	D.2.2 Be in MODE 4.	~~18~~ 84 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One Containment Pressure channel inoperable.	E.1 -------------NOTE------------- One additional channel may be bypassed for up to 12 4 hours for surveillance testing. ---------------------------------	
	Place channel in bypass.	72 ~~6~~ hours
	OR	
	E.2.1 Be in MODE 3.	78 ~~12~~ hours
	AND	
	E.2.2 Be in MODE 4.	84 ~~18~~ hours
F. One channel or train inoperable.	F.1 Restore channel or train to OPERABLE status.	48 hours
	OR	
	F.2.1 Be in MODE 3.	54 hours
	AND	
	F.2.2 Be in MODE 4.	60 hours
G. One Steam Line Isolation Manual Initiation - individual channel inoperable.	G.1 Restore channel to OPERABLE status.	48 hours
	OR	
	G.2 Declare associated steam line isolation valve inoperable.	48 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. One train inoperable.	H.1 -------------NOTE------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---------------------------------- Restore train to OPERABLE status.	~~6~~ 24 hours
	OR	
	H.2.1 Be in MODE 3.	~~12~~ 30 hours
	AND	
	H.2.2 Be in MODE 4.	~~18~~ 36 hours
I. One train inoperable.	I.1 -------------NOTE------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---------------------------------- Restore train to OPERABLE status.	~~6~~ 24 hours
	OR	
	I.2 Be in MODE 3.	~~12~~ 30 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
J. One channel inoperable.	J.1	-------------NOTE------------- The inoperable channel may be bypassed for up to 12 ~~4~~ hours for surveillance testing of other channels. ---------------------------------- Place channel in trip.	72 ~~6~~ hours
	OR		
	J.2	Be in MODE 3.	78 ~~12~~ hours
K. One Main Feedwater Pumps trip channel inoperable.	K.1	Place channel in trip.	1 hour
	OR		
	K.2	Be in MODE 3.	7 hours
L. One channel inoperable.	L.1	-------------NOTE------------- One channel may be bypassed for up to 2 hours for surveillance testing provided the other channel is OPERABLE. ---------------------------------- Be in MODE 3.	6 hours

(continued)

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

	SURVEILLANCE	FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	92 31 days on a STAGGERED TEST BASIS
SR 3.3.2.3	---------------------------NOTE--------------------------- Final actuation of pumps or valves not required. -- Perform TADOT.	31 days
SR 3.3.2.4	Perform MASTER RELAY TEST.	92 31 days on a STAGGERED TEST BASIS
SR 3.3.2.5	Perform COT.	184 92 days
SR 3.3.2.6	Perform SLAVE RELAY TEST.	92 days <u>OR</u> 18 months for only Westinghouse AR and Potter & Brumfield MDR relay types
SR 3.3.2.7	Perform COT.	31 days

(continued)

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.6-1 to determine which SRs apply for each Containment Air Release and Addition Isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1	Perform ACTUATION LOGIC TEST.	92 31 days on a STAGGERED TEST BASIS
SR 3.3.6.2	Perform MASTER RELAY TEST.	92 31 days on a STAGGERED TEST BASIS
SR 3.3.6.3	Perform SLAVE RELAY TEST.	92 days <u>OR</u> 18 months for only Westinghouse AR and Potter & Brumfield MDR relay types
SR 3.3.6.4	------------------------------NOTE------------------------------ Verification of setpoint is not required. --- Perform TADOT.	 18 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.9.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.9.2	Perform COT.	31 days
SR 3.3.9.3	Verify each automatic valve moves to the correct position and Reactor Makeup Water pumps stop upon receipt of an actual or simulated actuation signal.	18 months
SR 3.3.9.4	-------------------------------NOTE------------------------------ Only required to be performed when used to satisfy Required Action A.3 or B.3. --- Perform CHANNEL CHECK on the Source Range Neutron Flux Monitors.	12 hours
SR 3.3.9.5	-------------------------------NOTE------------------------------ Only required to be performed when used to satisfy Required Action A.3 or B.3. --- Verify combined flowrates from both Reactor Makeup Water Pumps are ≤ the value in the COLR.	31 days
SR 3.3.9.6	-------------------------------NOTE------------------------------ Only required to be performed when used to satisfy Required Action A.3 or B.3. --- Perform COT on the Source Range Neutron Flux Monitors.	184 ~~92~~ days

ATTACHMENT 2

MARKUP OF TECHNICAL SPECIFICATIONS PAGES FOR MCGUIRE

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One channel inoperable.	------------------NOTE------------------ One channel may be bypassed for up to 4 hours for surveillance testing and setpoint adjustment. ---	
	D.1.1 Place channel in trip.	6 hours
	AND	
	D.1.2 Reduce THERMAL POWER to ≤ 75% RTP.	12 hours
	OR	
	D.2.1 Place channel in trip.	6 hours
	AND	
	------------------NOTE------------------ Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. ---	
	D.2.2 Perform SR 3.2.4.2.	Once per 12 hours
	OR	
	D.3 Be in MODE 3.	12 hours

(continued)

INSERT

INSERTS

INSERT FOR MCGUIRE TS 3.3.1, CONDITION D

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One channel inoperable.	------------------NOTE------------------ One channel may be bypassed for up to 12 hours for surveillance testing and setpoint adjustment. ---	
	D.1.1 -------------NOTE------------- Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. ------------------------------------ Perform SR 3.2.4.2.	12 hours from discovery of THERMAL POWER > 75% RTP <u>AND</u> Once per 12 hours thereafter
	<u>AND</u> D.1.2 Place channel in trip.	72 hours
	<u>OR</u> D.2 Be in MODE 3.	78 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One channel inoperable.	------------------NOTE------------------ One channel may be bypassed for up to ~~4~~ 12 hours for surveillance testing. --	
	E.1 Place channel in trip.	~~6~~ 72 hours
	OR	
	E.2 Be in MODE 3.	~~12~~ 78 hours
F. THERMAL POWER > P-6 and < P-10, one Intermediate Range Neutron Flux channel inoperable.	F.1 Reduce THERMAL POWER to < P-6.	~~2~~ 24 hours
	OR	
	F.2 Increase THERMAL POWER to > P-10.	~~2~~ 24 hours
	-----------------NOTE--------------- Limited boron concentration changes associated with RCS inventory control or limited plant temperature changes are allowed. --	
G. THERMAL POWER > P-6 and < P-10, two Intermediate Range Neutron Flux channels inoperable.	G.1 Suspend operations involving positive reactivity additions.	Immediately
	AND	
	G.2 Reduce THERMAL POWER to < P-6.	2 hours
H. THERMAL POWER < P-6, one or two Intermediate Range Neutron Flux channels inoperable.	H.1 Restore channel(s) to OPERABLE status.	Prior to increasing THERMAL POWER to > P-6

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
M. One channel inoperable.	------------------NOTE------------------ One channel may be bypassed for up to ~~4~~ hours for surveillance testing. 12 ---	72
	M.1 Place channel in trip.	~~6~~ hours
	<u>OR</u>	78
	M.2 Reduce THERMAL POWER to < P-7.	~~12~~ hours
N. One Reactor Coolant Flow - Low (Single Loop) channel inoperable.	------------------NOTE------------------ One channel may be bypassed for up to ~~4~~ hours for surveillance testing. 12 ---	72
	N.1 Place channel in trip.	~~6~~ hours
	<u>OR</u>	76
	N.2 Reduce THERMAL POWER to < P-8.	~~10~~ hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
O. One Turbine Trip - Low Fluid Oil Pressure channel inoperable.	------------------NOTE------------------ One channel may be bypassed for up to ~~4~~ 12 hours for surveillance testing. ---	
	O.1 Place channel in trip.	~~6~~ 72 hours
	<u>OR</u>	
	O.2 Reduce THERMAL POWER to < P-8.	~~10~~ 76 hours
P. One or more Turbine Trip - Turbine Stop Valve Closure channels inoperable.	P.1 Place channel(s) in trip.	~~6~~ 72 hours
	<u>OR</u>	
	P.2 Reduce THERMAL POWER to < P-8.	~~10~~ 76 hours
Q. One train inoperable.	------------------NOTE------------------ One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---	
	Q.1 Restore train to OPERABLE status.	~~6~~ 24 hours
	<u>OR</u>	
	Q.2 Be in MODE 3.	~~12~~ 30 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
R. One RTB train inoperable.	------NOTE~~S~~------ ~~1.~~ One train may be bypassed for up to ~~2~~ 4 hours for surveillance testing, provided the other train is OPERABLE. ~~2. One RTB may be bypassed for up to 2 hours for maintenance on undervoltage or shunt trip mechanisms, provided the other train is OPERABLE.~~ ------------	
	R.1 Restore train to OPERABLE status.	~~1~~ 24 hour(s)
	OR	
	R.2 Be in MODE 3.	~~7~~ 30 hours
S. One or more channel(s) inoperable.	S.1 Verify interlock is in required state for existing unit conditions.	1 hour
	OR	
	S.2 Be in MODE 3.	7 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.4	------------------------------NOTES------------------------------ This Surveillance must be performed on the reactor trip bypass breaker prior to placing the bypass breaker in service. -- Perform TADOT.	62 ~~31~~ days on a STAGGERED TEST BASIS
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	92 ~~31~~ days on a STAGGERED TEST BASIS
SR 3.3.1.6	------------------------------NOTES------------------------------ Not required to be performed until 24 hours after THERMAL POWER is ≥ 75% RTP. -- Calibrate excore channels to agree with incore detector measurements.	92 EFPD
SR 3.3.1.7	------------------------------NOTES------------------------------ Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entry into MODE 3. -- Perform COT.	184 ~~92~~ days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.8	------------------------------NOTES------------------------------ This Surveillance shall include verification that interlocks P-6 (for the Intermediate Range channels) and P-10 (for the Power Range channels) are in their required state for existing unit conditions. -- Perform COT.	---------NOTE------- Only required when not performed within previous ~~92~~ 184 days --------------------------- Prior to reactor startup <u>AND</u> Four hours after reducing power below P-10 for power and intermediate range instrumentation <u>AND</u> Four hours after reducing power below P-6 for source range instrumentation <u>AND</u> Every ~~92~~ 184 days thereafter

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train inoperable.	C.1 -------------NOTE-------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ------------------------------------	
	Restore train to OPERABLE status.	~~6~~ 24 hours
	OR	
	C.2.1 Be in MODE 3.	~~12~~ 30 hours
	AND	
	C.2.2 Be in MODE 5.	~~42~~ 60 hours
D. One channel inoperable.	D.1 -------------NOTE-------------- One channel may be bypassed for up to ~~4~~ 12 hours for surveillance testing. ------------------------------------	
	Place channel in trip.	~~6~~ 72 hours
	OR	
	D.2.1 Be in MODE 3.	~~12~~ 78 hours
	AND	
	D.2.2 Be in MODE 4.	~~18~~ 84 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One Containment Pressure channel inoperable.	E.1 -------------NOTE-------------- One additional channel may be bypassed for up to ~~4~~ 12 hours for surveillance testing. ---------------------------------- Place channel in bypass.	72 ~~6~~ hours
	OR	
	E.2.1 Be in MODE 3.	78 ~~12~~ hours
	AND	
	E.2.2 Be in MODE 4.	84 ~~18~~ hours
F. One channel or train inoperable.	F.1 Restore channel or train to OPERABLE status.	48 hours
	OR	
	F.2.1 Be in MODE 3.	54 hours
	AND	
	F.2.2 Be in MODE 4.	60 hours
G. One Steam Line Isolation Manual Initiation - individual channel inoperable.	G.1 Restore channel to OPERABLE status.	48 hours
	OR	
	G.2 Declare associated steam line isolation valve inoperable.	48 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. One train inoperable.	H.1 -------------NOTE------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ----------------------------------- Restore train to OPERABLE status.	24 ~~6~~ hours
	<u>OR</u>	
	H.2.1 Be in MODE 3.	30 ~~12~~ hours
	<u>AND</u>	
	H.2.2 Be in MODE 4.	36 ~~18~~ hours
I. One train inoperable.	I.1 -------------NOTE------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ----------------------------------- Restore train to OPERABLE status.	24 ~~6~~ hours
	<u>OR</u>	
	I.2 Be in MODE 3.	30 ~~12~~ hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. One channel inoperable.	J.1 -------------NOTE-------------- One channel may be bypassed for up to ~~4~~ 12 hours for surveillance testing. ---------------------------------- Place channel in trip.	~~6~~ 72 hours
	OR	
	J.2 Be in MODE 3.	~~12~~ 78 hours
K. One Main Feedwater Pumps trip channel inoperable.	K.1 Place channel in trip.	1 hours
	OR	
	K.2 Be in MODE 3.	7 hours
L. One required channel in one train of Doghouse Water Level-High High inoperable.	L.1 Restore the inoperable train to OPERABLE status.	72 hours
	OR	
	L.2 Perform continuous monitoring of Doghouse water level.	73 hours
M. Two trains of Doghouse Water Level-High High inoperable.	M.1 Perform continuous monitoring of Doghouse water level..	1 hour

(continued)

SURVEILLANCE REQUIREMENTS

--NOTE--
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	~~31~~ 92 days on a STAGGERED TEST BASIS
SR 3.3.2.3	Perform COT.	31 days
SR 3.3.2.4	Perform MASTER RELAY TEST.	~~31~~ 92 days on a STAGGERED TEST BASIS
SR 3.3.2.5	Perform COT.	~~92~~ 184 days
SR 3.3.2.6	Perform SLAVE RELAY TEST.	92 days
SR 3.3.2.7	--------------------NOTE-------------------- Verification of setpoint not required for manual initiation functions. --- Perform TADOT.	18 months

(continued)

ATTACHMENT 3

PROPOSED TECHNICAL SPECIFICATION BASES CHANGES FOR CATAWBA

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal:

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

This action addresses the train orientation of the SSPS 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 condition in which the requirement does not apply. To achieve this status, the RTBs must be opened within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With the RTBs open, 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.

and D.2

D.1.1, D.1.2, ~~D.2.1, D.2.2, and~~ D.3

INSERT

Condition D applies to the Power Range Neutron Flux—High and Power Range Neutron Flux-High Positive Rate Functions.

The NIS power range detectors provide input to the CRD System and the SG Water Level 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 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~~).

72 14333 10

INSERTS

INSERT FOR CATAWBA BASES 3.3.1, CONDITION D

With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost. Therefore, SR 3.2.4.2 must be performed (Required Action D.1.1) within 12 hours of THERMAL POWER exceeding 75% RTP and once per 12 hours thereafter. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels> 75% RTP. At power levels $\leq$ 75% RTP, operation of the core with radial power distributions beyond the design limits, at a power level where DNB conditions may exist, is prevented. The 12 hour Completion Time is consistent with the Surveillance Requirement Frequency in LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)." Required Action D.1.1 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using movable incore detectors may not be necessary.

BASES

ACTIONS (continued)

In addition to placing the inoperable channel in the tripped condition, THERMAL POWER must be reduced to ≤ 75% RTP within 12 hours. Reducing the power level prevents operation of the core with radial power distributions beyond the design limits. With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost.

As an alternative to the above actions, the inoperable channel can be placed in the tripped condition within 6 hours and the QPTR monitored once every 12 hours per SR 3.2.4.2, QPTR verification. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels ≥ 75% RTP. The 6 hour Completion Time and the 12 hour Frequency are consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

The 78-hour Completion Time includes 72 hours for channel corrective maintenance, and an additional 6 hours for the MODE reduction as required by Required Action D.2.

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Twelve 78 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 ~~4~~ 12 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. The ~~4~~ 12 hour time limit is justified in Reference ~~7~~ 10.

~~Required Action D.2.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using the movable incore detectors once per 12 hours may not be necessary.~~

BASES

ACTIONS (continued)

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; and
- SG Water Level-Low Low.

72 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-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. 72 10

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 4 hours while performing routine surveillance testing of the other channels. The 4 hour time limit is justified in Reference 7. 12 12 10

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below

BASES

ACTIONS (continued)

24

the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 2 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase to THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

G.1 and G.2

Condition G applies to two inoperable Intermediate Range Neutron Flux trip channels 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, the 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. Required Action G.1 is modified by a Note to indicate that normal plant control operations that individually add limited positive reactivity (e.g., temperature or boron fluctuations associated with RCS inventory management or temperature control) are not precluded by this

BASES

ACTIONS (continued)

K.1 and K.2

Condition K applies to one inoperable source range channel in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the source range channels inoperable, 48 hours is allowed to restore it to an OPERABLE status. If the channel cannot be returned to an OPERABLE status, 1 additional hour is allowed to open the RTBs. Once the RTBs are open, the core is in a more stable condition and the unit exits this condition. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour to open the RTBs, are justified in Reference 7.

L.1 and L.2

Condition L applies to the following reactor trip Functions:

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

With one channel inoperable, the inoperable channel must be placed in the tripped condition within ~~6~~ 72 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 7 (and below the P-8 setpoint for the Reactor Coolant Flow-Low (Two Loops) Function). These Functions do not have to be OPERABLE below the P-7 setpoint because, for the Pressurizer Water Level-High function, transients are slow enough for manual action; and for the other functions, power distributions that would cause a DNB concern at this low power level are unlikely. The ~~6~~ 72 hours allowed to place the channel in the tripped

BASES

ACTIONS (continued)

condition is justified in Reference ~~7~~ 10. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

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 L.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to ~~4~~ 12 hours while performing routine surveillance testing of the other channels. The ~~4~~ 12 hour time limit is justified in Reference ~~7~~ 10.

M.1 and M.2

Condition M applies to the Reactor Coolant Flow-Low (Single Loop) reactor trip Function. With one channel inoperable, the inoperable channel must be placed in trip within ~~6~~ 72 hours. If the channel cannot be restored to OPERABLE status or the channel placed in trip within the ~~6~~ 72 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 trip Function does not have to be OPERABLE below the P-8 setpoint because other RTS trip Functions provide core protection below the P-8 setpoint. The ~~6~~ 72 hours allowed to restore the channel to OPERABLE status or place in trip and the 4 additional hours allowed to reduce THERMAL POWER to below the P-8 setpoint are justified in Reference ~~7~~ 10.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to ~~4~~ 12 hours while performing routine surveillance testing of the other channels. The ~~4~~ 12 hour time limit is justified in Reference ~~7~~ 10.

BASES

ACTIONS (continued)

N.1, N.2, 0.1, and 0.2

Stop Valve EH Pressure Low

Condition N and 0 apply to Turbine Trip on ~~Low Fluid Oil Pressure~~ or on Turbine Stop Valve Closure. With one channel inoperable, the inoperable channel must be placed in the trip condition within ~~6~~ 72 hours. If placed in the tripped condition, this results in a partial trip condition requiring fewer additional channels 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-9 setpoint within the next 4 hours. The ~~6~~ 72 hours allowed to place the inoperable channel in the tripped condition and the 4 hours allowed for reducing power are justified in Reference ~~7~~ 10.

The Required Actions of Condition N have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to ~~4~~ 12 hours while performing routine surveillance testing of the other channels. The ~~4~~ 12 hour time limit is justified in Reference ~~7~~ 10.

P.1 and P.2

Condition P applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one train inoperable, ~~6~~ 24 hours are allowed to restore the train to OPERABLE status (Required Action P.1) or the unit must be placed in MODE 3 within the next 6 hours. ~~The Completion Time of 6~~ 24 ~~hours (Required Action P.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 24 hours allowed to restore the inoperable RTS Automatic Trip Logic train to OPERABLE status is justified in Reference 10. The additional Completion Time of 6 hours (Required Action P.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 4 hours for surveillance testing, provided the other train is OPERABLE. The 4 hour time limit for testing the RTS Automatic Trip Logic train may include testing the RTB also, if both the Logic test and RTB test are conducted within the 4 hour time limit. The 4 hour time limit is justified in Reference 10.

BASES

ACTIONS (continued)

The 24 hour Completion Time is justified in Reference 11.

Q.1 and Q.2

24 hours

for train corrective maintenance

Condition Q applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS 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 RTS Function.~~ Placing the unit in MODE 3 removes the requirement for this particular Function.

4 a The

The Required Actions have been modified by two Notes. Note 1 allows one RTB to be bypassed for up to 2 hours for surveillance testing, provided the other RTB 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.

4

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R.1 and R.2

Condition R applies to the P-6 and P-10 interlocks. With one or more channel(s) 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, by visual observation of the control room status lights, 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 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 RTS Function.

BASES

SURVEILLANCE REQUIREMENTS (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 and overpower 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 $\geq$ 3%. Note 2 clarifies that the Surveillance is required only if reactor power is $\geq$ 15% RTP and that 24 hours is allowed for completing the first Surveillance after reaching 15% 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~~ 62 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 for bypass breakers is included in SR 3.3.1.14. The bypass 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~~ 62 days on a STAGGERED TEST BASIS is ~~adequate. It is based on industry operating experience, considering instrument reliability and operating history data~~ justified in Reference 11.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested every ~~31~~ 92 days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypass

SURVEILLANCE REQUIREMENTS (continued)

condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. The Frequency of every 92 31 days on a STAGGERED TEST BASIS is ~~adequate. It is based on industry operating experience, considering instrument reliability and operating history data~~ justified in Reference 11.

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 and overpower ΔT Function.

At Beginning of Cycle (BOC), the excore channels are compared to the incore detector measurements prior to exceeding 75% power. Excore detectors are adjusted as necessary. This low power surveillance satisfies the initial performance of SR 3.3.1.6 with subsequent surveillances conducted at least every 92 EFPD.

At BOC, after reaching full power steady state conditions, additional incore and excore measurements are taken at various ΔI conditions to determine the M_j factors. The M_j factors are normally only determined at BOC, but they may be changed at other points in the fuel cycle if the relationship between excore and incore measurements changes significantly.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is > 75% RTP and that 24 hours is allowed for completing the first surveillance after reaching 75% RTP.

The Frequency of 92 EFPD is adequate. It is based on industry 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 184 92 days.

A COT is performed on each required channel to ensure the channel will

BASES

SURVEILLANCE REQUIREMENTS (continued)

perform the intended Function.

The tested portion of the loop must trip within the Allowable Values specified in Table 3.3.1-1.

The setpoint shall be left set consistent with the assumptions of the setpoint methodology.

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 a short time 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 completed within 4 hours after entry into MODE 3.

The Frequency of 92 days is justified in Reference 7. 11

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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, during the Intermediate Range COT, and P-10, during the Power Range COT, interlocks are in their required state for the existing unit condition. The verification is performed by visual observation of the permissive status light in the unit control room. 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 four hours after reducing power below P-10 and P-6. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels. The Frequency of "4 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 and four hours after reducing power below P-10 or P-6. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels.

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184

BASES

SURVEILLANCE REQUIREMENTS (continued)

Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the 4 hour limit. Four hours is 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 after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 4 hours.

The Frequency of 184 days is justified in Reference 11.

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.

SR 3.3.1.10

A CHANNEL CALIBRATION is performed every 18 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.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the setpoint methodology.

The Frequency of 18 months is based on the assumption of an 18 month calibration interval in 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. The applicable time constants are shown in Table 3.3.1-1.

BASES

SURVEILLANCE REQUIREMENTS (continued)

time could be affected is replacing the sensing assembly of a transmitter.

As appropriate, each channel's response must be verified every 18 months on a STAGGERED TEST BASIS. Testing of the final actuation devices is included in the testing. Testing of the RTS RTDs is performed on an 18 month frequency. Response times cannot be determined during unit operation because equipment operation is required to measure response times. Experience has shown that these components usually pass this surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.3.1.16 is modified by a Note stating that neutron detectors are excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response. The response time of the neutron flux signal portion of the channel shall be measured from detector output or input of the first electronic component in the channel.

REFERENCES

1. UFSAR, Chapter 7.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.
4. IEEE-279-1971.
5. 10 CFR 50.49.
6. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).
7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
8. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" Sep., 1995.
9. WCAP-14036-P-A Revision 1, "Elimination of Periodic Protection Channel Response Time Tests" Oct., 1998.
10. WCAP-14333-P-A, Rev. 1, October 1998.
11. WCAP-15376-P-A, Rev. 1, March 2003.

BASES

ACTIONS (continued)

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;
- Phase B Isolation; and
- Automatic Switchover to Containment Sump.

The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 13.

This action addresses the train orientation of the SSPS and the master and slave relays. If one train is inoperable, ~~6~~ 24 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 the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (~~12~~ 30 hours total time) and in MODE 5 within an additional 30 hours (~~42~~ 60 hours total time). 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 an individual SSPS slave relay or slave relay contact is incapable of actuating, then the equipment operated by the slave relay or slave relay contact is inoperable. An SSPS train is not inoperable due to an individual SSPS slave relay or slave relay contact being incapable of actuating.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. The Required Actions are not required to be met during this time, unless the train is discovered inoperable during the testing. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 7) that 4 hours is the average time required to perform ~~channel~~ train surveillance.

ACTIONS (continued)

D.1, D.2.1, and D.2.2

Condition D applies to:

- Containment Pressure-High;
- Pressurizer Pressure-Low;
- Steam Line Pressure-Low;
- Steam Line Pressure-Negative Rate-High;
- Loss of offsite power;
- SG Water level—Low Low; and
- SG Water level—High High (P-14) for the Feedwater Isolation Function.

The 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition is justified in Reference 13.

72

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.

72

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.

12

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 4 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, and the~~ 4 hours allowed for testing, are justified in Reference 7.

The 12   is   13

ACTIONS (continued)

E.1, E.2.1, and E.2.2

Condition E applies to:

- Containment Spray Containment Pressure-High High;
- Containment Phase B Isolation Containment Pressure-High High; and
- Steam Line Isolation Containment Pressure - High High.

None of these signals has input to a control function. Thus, two-out-of-three logic is necessary to meet acceptable protective requirements. However, a two-out-of-three design would require tripping a failed channel. This is undesirable because a single failure would then cause spurious containment spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented. Therefore, these channels are designed with two-out-of-four logic so that a failed channel may be bypassed rather than tripped. Note that one channel may be bypassed and still satisfy the single failure criterion. Furthermore, with one channel bypassed, a single instrumentation channel failure will not spuriously initiate containment spray.

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel should not be placed in the tripped condition. Instead it is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypass condition within ~~6~~ 72 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The Completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel to OPERABLE status, or place it in the bypassed condition within ~~6~~ 72 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 4 12 hours for surveillance testing. Placing a second channel in the bypass condition for up to 4 hours for testing purposes is acceptable based on the results of Reference 7 12 13.

ACTIONS (continued)

H.1, H.2.1 and H.2.2

Condition H applies to the automatic actuation logic and actuation relays for the Steam Line Isolation, Feedwater Isolation, and AFW actuation Functions.

24

The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 13.

The action addresses the train orientation of the SSPS and the master and slave 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. 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 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 4 hours is the average time required to perform channel surveillance.

If an individual SSPS slave relay or slave relay contact is incapable of actuating, then the equipment operated by the slave relay or slave relay contact is inoperable. An SSPS train is not inoperable due to an individual SSPS slave relay or slave relay contact being incapable of actuating.

I.1 and I.2

Condition I applies to the automatic actuation logic and actuation relays for the Turbine Trip Function.

24

The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 13.

This action addresses the train orientation of the SSPS and the master and slave 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. 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

ACTIONS (continued)

If an individual SSPS slave relay or slave relay contact is incapable of actuating, then the equipment operated by the slave relay or slave relay contact is inoperable. An SSPS train is not inoperable due to an individual SSPS slave relay or slave relay contact being incapable of actuating.

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 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 4 hours is the average time required to perform channel surveillance.

J.1 and J.2

Condition J applies to:

- SG Water Level—High High (P-14) for the Turbine Trip Function; and
- T_{avg}-Low.

The 72 hours allowed to restore the channel to OPERABLE status or place it in the tripped condition is justified in Reference 13.

If one channel is inoperable, ~~6~~ 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-three logic will result in actuation. ~~The 6 hour Completion Time is justified in Reference 7.~~ Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within ~~6~~ 72 hours requires the unit to be placed in MODE 3 within the following 6 hours. The allowed Completion Time of ~~6~~ 78 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, 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 ~~4~~ 12 hours for surveillance testing of other channels. The ~~6~~ 72 hours allowed to place the inoperable channel in the tripped condition, and the ~~4~~ 12 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference ~~7~~ 13.

BASES

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 channel I, train A and train B must be examined. Similarly, train A and train B must be examined when testing channel II, channel III, and channel IV (if applicable). 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 3.3.2.1

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, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.2.2

92

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested every 31 days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the

SURVEILLANCE REQUIREMENTS (continued)

semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and that there is an intact voltage signal path to the master relay coils. The Frequency of every ~~31~~ 92 days on a STAGGERED TEST BASIS is ~~adequate. It is based on industry operating experience, considering instrument reliability and operating history data~~

Justified in Reference 14

SR 3.3.2.3

SR 3.3.2.3 is the performance of a TADOT every 31 days. This test is a check of the Loss of Offsite Power Function. Each Function is tested up to, and including, the master transfer relay coils.

This test also includes trip devices that provide actuation signals directly to the SSPS. The SR is modified by a Note that excludes final actuation of pumps and valves to minimize plant upsets that would occur. The Frequency is adequate based on operating experience, considering instrument reliability and operating history data.

SR 3.3.2.4

SR 3.3.2.4 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 injected 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~~ 92 days on a STAGGERED TEST BASIS. The time allowed for the testing (4 hours) ~~and the surveillance interval are~~ is justified in Reference 7.

The Frequency of 92 days is justified in Reference 14.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a COT.

A COT is performed on each required channel to ensure the channel will perform the intended Function. The tested portion of the loop must trip within the Allowable Values specified in Table 3.3.2-1.

SURVEILLANCE REQUIREMENTS (continued)

The setpoint shall be left set consistent with the assumptions of the setpoint methodology.

The Frequency of ~~92~~ 184 days is justified in Reference ~~7~~ 14.

SR 3.3.2.6

SR 3.3.2.6 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 relay contact 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 by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. This test is performed every 92 days. The Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data.

For slave relays or any auxiliary relays in the ESFAS circuit that are of the type Westinghouse AR or Potter & Brumfield MDR, the SLAVE RELAY TEST is performed every 18 months. This test frequency is based on the relay reliability assessments presented in References 10, 11, and 12. These reliability assessments are relay specific and apply only to the Westinghouse AR and Potter & Brumfield MDR type relays. SSPS slave relays or any auxiliary relays not addressed by Reference 10 do not qualify for extended surveillance intervals and will continue to be tested at a 92 day Frequency.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a COT on the RWST level and Containment Pressure Control Start and Terminate Permissives.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.1-1. This test is performed every 31 days. The Frequency is adequate, based on operating experience, considering instrument reliability and operating history data.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 7.

3. UFSAR, Chapter 15.

4. IEEE-279-1971.

5. 10 CFR 50.49.

6. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

7. WCAP-10271-P-A, Supplement 1 and Supplement 2, Rev. 1, May 1986 and June 1990.

8. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" Sep., 1995.

9. WCAP-14036-P-A Revision 1, "Elimination of Periodic Protection Channel Response Time Tests" Oct., 1998.

10. WCAP-13900, "Extension of Slave Relay Surveillance Test Intervals," April 1994.

11. WCAP-13877 Revision 2-P-A, "Reliability Assessment of Westinghouse Type AR Relays Used As SSPS Slave Relays," August 2000.

12. WCAP-13878-P-A Revision 2, "Reliability Assessment of Potter & Brumfield MDR Series Relays," August 2000.

13. WCAP-14333-P-A, Revision 1, October 1998.

14. WCAP-15376-P-A, Revision 1, March 2003.

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 air release and addition isolation Functions.

SR 3.3.6.1

SR 3.3.6.1 is the performance of an ACTUATION LOGIC TEST. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and there is an intact voltage signal path to the master relay coils. This test is performed every ~~31~~ 92 days on a ~~STAGGERED TEST BASIS~~. The Surveillance interval is ~~acceptable based on instrument reliability and industry operating experience~~ justified in Reference 6.

SR 3.3.6.2

SR 3.3.6.2 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 injected 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~~ 92 days on a STAGGERED TEST BASIS. The Surveillance interval is ~~acceptable based on instrument reliability and industry operating experience~~ justified in Reference 6.

SR 3.3.6.3

SR 3.3.6.3 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 relay contact 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 by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. This test is performed every 92 days. The Frequency is acceptable based on instrument reliability and industry operating experience.

SURVEILLANCE REQUIREMENTS (continued)

For slave relays or any auxiliary relays in the circuit that are of the type Westinghouse AR or Potter & Brumfield MDR, the SLAVE RELAY TEST is performed every 18 months. This test frequency is based on the relay reliability assessments presented in References 3, 4, and 5. These reliability assessments are relay specific and apply only to the Westinghouse AR and Potter & Brumfield MDR type relays. SSPS slave relays or any auxiliary relays not addressed by Reference 3 do not qualify for extended surveillance intervals and will continue to be tested at a 92 day Frequency.

SR 3.3.6.4

SR 3.3.6.4 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and is performed every 18 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 test also includes trip devices that provide actuation signals directly to the SSPS, 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.

REFERENCES

1. 10 CFR 100.11.

2. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

3. WCAP-13900, "Extension of Slave Relay Surveillance Test Intervals," April 1994.

4. WCAP-13877 Revision 2-P-A, "Reliability Assessment of Westinghouse Type AR Relays Used as SSPS Slave Relays," August 2000.

5. WCAP-13878-P-A Revision 2, "Reliability Assessment of Potter & Brumfield MDR Series Relays," August 2000.

6. WCAP-15376-P-A, Revision 1, March 2003.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.9.5

SR 3.3.9.5 verifies the combined flow rates from both Reactor Makeup Water Pumps are within the value specified in the COLR. This surveillance is only required when implementing Required Action A.3 or B.3. It ensures the assumptions in the analysis for the boron dilution event under these conditions are satisfied.

This surveillance must be performed in conjunction with Required Action A.3 or B.3 and once per 31 days and is based on engineering judgement and the unlikely event that a boron dilution will occur during this time.

SR 3.3.9.6

SR 3.3.9.6 is the performance of a COT for the Source Range Neutron Flux monitors, which is the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify the OPERABILITY of required alarm, interlock, display, and trip functions. The COT also includes adjustments, as necessary, of the required alarm, interlock, and trip setpoints so that the setpoints are within the required range and accuracy. These monitors must be verified to operate with alarm setpoints less than or equal to 0.5 decade above the steady-state count rate. This SR is only required when the Source Range Neutron Flux Monitors are used to satisfy Required Action A.3 or B.3. This surveillance must be performed prior to placing the monitors in service for Required Action A.3 or B.3 and once per ~~92~~ 184 days thereafter. The ~~92~~ 184 day Frequency is ~~based on operating experience, which has been shown to be adequate.~~ Justified in Reference 3

REFERENCES

1. UFSAR, Chapter 15.

2. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

3. WCAP-15376-P-A, Rev. 1, March 2003.

ATTACHMENT 4

PROPOSED TECHNICAL SPECIFICATION BASES CHANGES FOR MCGUIRE

BASES

ACTIONS (continued)

sufficient time to accomplish the action in an orderly manner. With the RTBs open, 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.

and D.2

D.1.1, D.1.2, ~~D.2.1, D.2.2, and D.3~~

INSERT

Condition D applies to the Power Range Neutron Flux—High and Power Range Neutron Flux-High Positive Rate Functions.

The NIS power range detectors provide input to the CRD System and the SG Water Level 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 logic for actuation. The ~~6~~ hours allowed to place the inoperable channel in the tripped condition 72 is justified in WCAP-~~10271~~ 14333-P-A (Ref. ~~7~~ 10).

~~In addition to placing the inoperable channel in the tripped condition, THERMAL POWER must be reduced to ≤ 75% RTP within 12 hours. Reducing the power level prevents operation of the core with radial power distributions beyond the design limits. With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost.~~

~~As an alternative to the above actions, the inoperable channel can be placed in the tripped condition within 6 hours and the QPTR monitored once every 12 hours per SR 3.2.4.2, QPTR verification. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels ≥ 75% RTP. The 6 hour Completion Time and the 12 hour Frequency are 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~~ 78 hours are allowed to place the plant in MODE 3. The 78 hour Completion Time includes 72 hours for channel corrective maintenance, and an additional 6 hours for the MODE reduction as required by Required Action D.2. 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.

INSERTS

INSERT FOR MCGUIRE BASES 3.3.1, CONDITION D

With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost. Therefore, SR 3.2.4.2 must be performed (Required Action D.1.1) within 12 hours of THERMAL POWER exceeding 75% RTP and once per 12 hours thereafter. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels> 75% RTP. At power levels ≤ 75% RTP, operation of the core with radial power distributions beyond the design limits, at a power level where DNB conditions may exist, is prevented. The 12 hour Completion Time is consistent with the Surveillance Requirement Frequency in LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)." Required Action D.1.1 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using movable incore detectors may not be necessary.

ACTIONS (continued)

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to ~~4~~ 12 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. The note also allows an OPERABLE channel to be placed in bypass without entering the Required Actions for up to ~~4~~ 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The ~~4~~ 12 hour time limit is justified in Reference ~~7~~ 10.

~~Required Action D.2.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using the movable incore detectors once per 12 hours may not be necessary.~~

<u>E.1 and E.2</u>

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux—Low;
- Overtemperature ΔT;
- Overpower ΔT;
- Pressurizer Pressure—High; and
- SG Water Level—Low Low.

A known inoperable channel must be placed in the tripped condition within ~~6~~ 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-three logic for actuation of the two-out-of-four trips. The ~~6~~ 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference ~~7~~ 10.

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.

BASES

ACTIONS (continued)

12

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing routine surveillance testing of the other channels. The note also allows an OPERABLE channel to be placed in bypass without entering the Required Actions for up to 4 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 12 4 hour time limit is justified in Reference 7 10.

12

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less 24 than the P-10 setpoint, 2 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase to THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

G.1 and G.2

Condition G applies to two inoperable Intermediate Range Neutron Flux trip channels 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

BASES

ACTIONS (continued)

additions; therefore, core reactivity should not be increasing, and a 12 hour Frequency is adequate. The Completion Times of within 1 hour and once per 12 hours are based on operating experience in performing the Required Actions and the knowledge that unit conditions will change slowly. Required Action L.1 is modified by a note which permits plant temperature changes provided the temperature change is accounted for in the calculated SDM and that Keff remains < 0.99. Introduction of temperature changes including temperature increases when a positive MTC exists, must be evaluated to ensure they do not result in a loss of required SDM or adequate margin to criticality.

M.1 and M.2

Condition M applies to the following reactor trip Functions:

- Pressurizer Pressure—Low;
- Pressurizer Water Level—High;
- Reactor Coolant Flow—Low (Two Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs. 72

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 (and below the P-8 setpoint for the Reactor Coolant Flow-Low (Two Loops) Function). These Functions do not have to be OPERABLE below the P-7 setpoint because, for the Pressurizer Water Level-High function, transients are slow enough for manual action; and for the other functions, power distributions that would cause a DNB concern at this low power level are unlikely. The 72 6 hours allowed to place the channel in the tripped condition is justified in Reference 7. 10 An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

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 M.

BASES

ACTIONS (continued)

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing routine surveillance testing of the other channels. The note also allows an OPERABLE channel to be placed in bypass without entering the Required Actions for up to 4 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 4 hour time limit is justified in Reference 7.

N.1 and N.2

Condition N applies to the Reactor Coolant Flow—Low (Single Loop) reactor trip Function. With one channel inoperable, the inoperable channel must be placed in trip within 6 hours. If the channel cannot be restored to OPERABLE status or the channel placed in trip 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 trip Function does not have to be OPERABLE below the P-8 setpoint because other RTS trip Functions provide core protection below the P-8 setpoint. The 6 hours allowed to restore the channel to OPERABLE status or place in trip and the 4 additional hours allowed to reduce THERMAL POWER to below the P-8 setpoint 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 4 hours while performing routine surveillance testing of the other channels. The note also allows an OPERABLE channel to be placed in bypass without entering the Required Actions for up to 4 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 4 hour time limit is justified in Reference 7.

O.1, O.2, P.1, and P.2

Condition O and P apply to Turbine Trip on Low Fluid Oil Pressure or on Turbine Stop Valve Closure. With a 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 fewer 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 4 hours. The 6 hours allowed to place the inoperable channel in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 7.

BASES

ACTIONS (continued)

The Required Actions of Condition O have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 ~~4~~ hours while performing routine surveillance testing of the other channels. The note also allows an OPERABLE channel to be placed in bypass without entering the Required Actions for up to 12 ~~4~~ hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The ~~4~~ 12 hour time limit is justified in Reference ~~7~~ 10.

Q.1 and Q.2

Condition Q applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one train inoperable, 24 ~~6~~ hours are allowed to restore the train to OPERABLE status (Required Action Q.1) or the unit must be placed in MODE 3 within the next 6 hours. ~~The Completion Time of 6 hours (Required Action Q.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.~~ 24 The additional Completion Time of 6 hours (Required Action Q.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

The 24 hours allowed to restore the inoperable RTS Automatic Trip Logic train to OPERABLE status is justified in Reference 10.

The Required Actions have been modified by a Note that allows bypassing one train up to 4 hours for surveillance testing, provided the other train is OPERABLE.

The 4 hour time limit for testing the RTS Automatic Trip Logic train may include testing the RTB also, if both the Logic test and RTB test are conducted within the 4 hour time limit. The 4 hour time limit is justified in Reference 10.

R.1 and R.2

Condition R applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one train inoperable, ~~1 hour~~ 24 hours is allowed for train corrective maintenance 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 RTS Function.~~ Placing the unit in MODE 3 removes the requirement for this particular Function.

The 24 hour Completion Time is justified in Reference 11.

BASES

ACTIONS (continued)

The Required Actions have been modified by ~~two~~ a Note~~s~~. The Note ~~1~~ allows one RTB to be bypassed for up to ~~2~~ 4 hours for surveillance testing, provided the other RTB 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~~ 4 hour time limit is justified in Reference ~~7~~ 11.

S.1 and S.2

Condition S applies to the P-6 and P-10 interlocks. With one or more channel(s) 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, by visual observation of the control room status lights, 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 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 RTS Function.

T.1 and T.2

Condition T applies to the P-7, P-8, and P-13 interlocks. With one or more channel(s) 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, by visual observation of the control room status lights, 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

is required only if reactor power is ≥ 15% RTP and that 12 hours is allowed for completing 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. Maintaining the 2% agreement is only applicable during equilibrium conditions.

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 in AFD is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted.

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 and overpower 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%. Note 2 clarifies that the Surveillance is required only if reactor power is ≥ 15% RTP and that 24 hours is allowed for completing the first Surveillance after reaching 15% 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~~ 62 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 for bypass breakers is included in SR 3.3.1.14. The bypass 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.

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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.~~ Justified in Reference 11

SR 3.3.1.5

92

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested every ~~31~~ days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. 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.~~ 92 justified in Reference 11

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 and overpower ΔT Function.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is $\geq$ 75% RTP and that 24 hours is allowed for completing the first surveillance after reaching 75% RTP.

The Frequency of 92 EFPD is adequate. It is based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.7

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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 channel will perform the intended Function.

The tested portion of the Loop must trip within the Allowable Values specified in Table 3.3.1-1.

The setpoint shall be left set consistent with the assumptions of the setpoint methodology.

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 a short time 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 completed within 4 hours after entry into MODE 3. The surveillance shall include verification of the high flux at shutdown alarm setpoint of less than or equal to the average CPS Neutron Level reading (most consistent value between highest and lowest CPS Neutron Level reading) at five times background.

The Frequency of 92 days is justified in Reference 7.

184 11

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, during the Intermediate Range COT, and P-10, during the Power Range COT, interlocks are in their required state for the existing unit condition. The verification is performed by visual observation of the permissive status light in the unit control room. 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 four hours after reducing power below P-10 and P-6. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels. The Frequency of "4 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

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BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of 184 days is justified in Reference 11.

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~~ 184 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup and four hours after reducing power below P-10 or P-6. The MODE of Applicability for this 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 or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the 4 hour limit. Four hours is 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 after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 4 hours.

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.

SR 3.3.1.10

The CHANNEL CALIBRATION may be performed at power or during refueling based on bypass testing capability. Channel unavailability evaluations in References 10 and 11 have conservatively assumed that the CHANNEL CALIBRATION is performed at power with the channel in bypass.

A CHANNEL CALIBRATION is performed every 18 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.

Make new paragraph.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the setpoint methodology.

The Frequency of 18 months is based on the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

BASES

REFERENCES

1. UFSAR, Chapter 7.

2. UFSAR, Chapter 6.

3. UFSAR, Chapter 15.

4. IEEE-279-1971.

5. 10 CFR 50.49.

6. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

8. WCAP 13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" Sep., 1995.

9. WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests" Oct., 1998.

10. WCAP-14333-P-A, Revision 1, October 1998,

11. WCAP-15376-P-A, Revision 1, March 2003.

BASES

ACTIONS (continued)

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.

This action addresses the train orientation of the SSPS and the master and slave relays. If one train is inoperable, ~~8~~ 24 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 the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (~~12~~ 30 hours total time) and in MODE 5 within an additional 30 hours (~~42~~ 60 hours total time). 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 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 10.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. The Required Actions are not required to be met during this time, unless the train is discovered inoperable during the testing. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 7) that 4 hours is the average time required to perform ~~channel~~ train surveillance.

If an individual SSPS slave relay or slave relay contact is incapable of actuating, then the equipment operated by the slave relay or slave relay contact is inoperable. An SSPS train is not inoperable due to an individual SSPS slave relay or slave relay contact being incapable of actuating.

D.1, D.2.1, and D.2.2

Condition D applies to:

- Containment Pressure-High;
- Pressurizer Pressure-Low Low;
- Steam Line Pressure-Low;

BASES

ACTIONS (continued)

- Steam Line Pressure-Negative Rate-High;
- SG Water Level – High High (P-14) for the Feedwater Isolation Function.
- SG Water level-Low Low, and
- Loss of offsite power.

If one channel is inoperable, ~~6~~ 72 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. The 72 hours allowed to restore the channel to OPERABLE status or placed in the tripped condition is justified in Reference 10.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within ~~6~~ 72 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 ~~4~~ 12 hours for surveillance testing of other channels. The note also allows an OPERABLE channel to be placed in bypass without entering the Required Actions for up to ~~4~~ 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. ~~The 6 hours allowed to restore the channel to OPERABLE status or to place the inoperable channel in the tripped condition, and the~~ The 12 ~~4~~ hours allowed for testing, are justified in Reference ~~7~~ 10.

E.1, E.2.1, and E.2.2

Condition E applies to:

- Containment Spray Containment Pressure - High High;
- Containment Phase B Isolation Containment Pressure - High-High, and
- Steam Line Isolation Containment Pressure - High High.

BASES

ACTIONS (continued)

None of these signals has input to a control function. Thus, two-out-of-three logic is necessary to meet acceptable protective requirements. However, a two-out-of-three design would require tripping a failed channel. This is undesirable because a single failure would then cause spurious containment spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented. Therefore, these channels are designed with two-out-of-four logic so that a failed channel may be bypassed rather than tripped. Note that one channel may be bypassed and still satisfy the single failure criterion.

Furthermore, with one channel bypassed, a single instrumentation channel failure will not spuriously initiate containment spray.

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel should not be placed in the tripped condition. Instead it is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypass condition within 6 hours, 72 is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The Completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel to OPERABLE status, or place it in the 72 bypassed 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.

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The Required Actions are modified by a Note that allows one additional channel to be bypassed for up to 4 hours for surveillance testing. Placing a second channel in the bypass condition for up to 4 hours for testing purposes is acceptable based on the results of Reference 7.

10 12

F.1, F.2.1, and F.2.2

Condition F applies to:

- Manual Initiation of Steam Line Isolation; and
- P-4 Interlock.

BASES

ACTIONS (continued)

For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. If a train or channel is inoperable, 48 hours is allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of these Functions, the available redundancy, and the low probability of an event occurring during this interval. If the Function 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.

G.1 and G.2

Condition G applies to manual initiation of Steam Line Isolation.

This action addresses the operability of the manual steam line isolation function for each individual main steam isolation valve. If a channel is inoperable, 48 hours is allowed to return it to an OPERABLE status. If the train cannot be restored to OPERABLE status, the Conditions and Required Actions of LCO 3.7.2, "Main Steam Isolation Valves," must be entered for the associated inoperable valve. The specified Completion Time is reasonable considering that there is a system level manual initiation train for this Function and the low probability of an event occurring during this interval.

H.1, H.2.1 and H.2.2

Condition H applies to the automatic actuation logic and actuation relays for the Steam Line Isolation, Feedwater Isolation, and AFW actuation Functions.

The action addresses the train orientation of the SSPS and the master and slave relays for these functions. If one train is inoperable, ~~6~~ 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 10. 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. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly

BASES

ACTIONS (continued)

If an individual SSPS slave relay or slave relay contact is incapable of actuating, then the equipment operated by the slave relay or slave relay contact is inoperable. An SSPS train is not inoperable due to an individual SSPS slave relay or slave relay contact being incapable of actuating.

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 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 4 hours is the average time required to perform channel surveillance.

I.1 and I.2

Condition I applies to the automatic actuation logic and actuation relays for the Turbine Trip Function.

The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 10.

This action addresses the train orientation of the SSPS and the master and slave relays for this Function. If one train is inoperable, ~~6~~ 24 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the following 6 hours. 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 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 4 hours is the average time required to perform channel surveillance.

J.1 and J.2

Condition J applies to:

- SG Water Level-High High (P-14) for the Turbine Trip Function; and
- T_{avg}-Low.

BASES

ACTIONS (continued)

The 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition is justified in Reference 10.

If one channel is inoperable, 6 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-two logic will result in actuation. ~~The 6 hour Completion Time is justified in Reference 7.~~ Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 6 72 hours requires the unit to be placed in MODE 3 within the following 6 hours. The allowed Completion Time of 6 78 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, 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 4 12 hours for surveillance testing of other channels. The note also allows an OPERABLE channel to be placed in bypass without entering the Required Actions for up to 4 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 6 72 hours allowed to place the inoperable channel in the tripped condition, and the 4 12 hours allowed for a channel to be in the bypassed condition for testing, are justified in Reference 7 10.

K.1 and K.2

Condition K applies to the AFW pump start on trip of all MFW pumps.

This action addresses the relay contact orientation for the auto start function of the AFW System on loss of all MFW pumps. The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. If a channel is inoperable,
1 hour is allowed to place the channel in trip. If placed in the tripped condition, the function is then in a partial trip condition where a one-out-of-one logic will result in actuation. If the channel is not placed in trip within 1 hour, 6 hours are allowed 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.

L.1

Condition L applies to the Doghouse Water Level - High High.

The failure of one required channel in one train in either reactor building doghouse results in a loss of redundancy for the function. The function can still be initiated by the remaining operable train. The inoperable train is, required to

BASES

SURVEILLANCE REQUIREMENTS (continued)

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, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.2.2

92

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested every ~~31~~ days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and that there is an intact voltage signal path to the master relay coils. The Frequency of every 92 ~~31~~ days on a STAGGERED TEST BASIS is ~~adequate. It is based on industry operating experience, considering instrument reliability and operating history data.~~ justified in Reference 11

SR 3.3.2.3

SR 3.3.2.3 is the performance of a COT on the RWST level and Containment Pressure Control Start and Terminate Permissives.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3. 2-1. This test is performed every 31 days. The Frequency is adequate, based on operating experience, considering instrument reliability and operating history data.

SR 3.3.2.4

SR 3.3.2.4 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 injected to the slave relay coil.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. This test is performed every ~~31~~ 92 days on a STAGGERED TEST BASIS. The time allowed for the testing (4 hours) ~~and the surveillance interval are~~ is justified in Reference 7.

The Frequency of 92 days is justified in Reference 11.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a COT.

A COT is performed on each required channel to ensure the channel will perform the intended Function. The tested portion of the loop must trip within the Allowable Values specified in Table 3.3. 2-1.

The setpoint shall be left set consistent with the assumptions of the setpoint methodology.

The Frequency of ~~92~~ 184 days is justified in Reference ~~7~~ 11.

SR 3.3.2.6

SR 3.3.2.6 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 relay contact 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 by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. This test is performed every 92 days. The Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT. This test is a check of the Manual Actuation Functions, AFW pump start, Reactor Trip (P-4) Interlock and Doghouse Water Level - High High feedwater isolation. It is performed every 18 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

setpoints during the TADOT for manual initiation Functions. The manual initiation Functions have no associated setpoints.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a CHANNEL CALIBRATION.

Make new paragraph.

A CHANNEL CALIBRATION is performed every 18 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.

The CHANNEL CALIBRATION may be performed at power or during refueling based on bypass testing capability, channel unavailability evaluations in References 10 and 11 have conservatively assumed that the CHANNEL CALIBRATION is performed at power with the channel in bypass.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology.

The Frequency of 18 months is based on the assumption of an 18 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. The applicable time constants are shown in Table 3.3.2-1.

SR 3.3.2.9

This SR ensures the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. Response Time testing acceptance criteria are included in the UFSAR (Ref. 2). Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Trip Setpoint value at the sensor, to the point at which the equipment in both trains reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position).

For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer functions set to one with the resulting measured response time compared to the appropriate UFSAR response time. Alternately, the response time test can be performed with the time constants set to their nominal value provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

BASES

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 7.
3. UFSAR, Chapter 15.
4. IEEE-279-1971.
5. 10 CFR 50.49.
6. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).
7. WCAP-10271-P-A, Supplement 1 and Supplement 2, Rev. 1, May 1986 and June 1990.
8. WCAP 13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" Sep., 1995.
9. WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests" Oct., 1998.
10. WCAP-14333-P-A, Revision 1, October 1998.
11. WCAP-15376-P-A, Revision 1, March 2003.

ATTACHMENT 5

SUMMARY OF REGULATORY COMMITMENTS

SUMMARY OF REGULATORY COMMITMENTS

The following table identifies those actions committed to by Duke in this document. Any other statements in this submittal are provided for information purposes and are not considered to be commitments. Please direct questions regarding these commitments to Mr. L. J. Rudy, Regulatory Compliance, Catawba Nuclear Station (803) 831-3084 or Mr. P. T. Vu, Regulatory Compliance, McGuire Nuclear Station (704) 875-4302.

COMMITMENT	Due Date/Event
The proposed changes to the Catawba and McGuire Nuclear Stations Technical Specifications will be implemented within 90 days of NRC approval.	Within 90 days of NRC approval.
Activities that degrade the availability of auxiliary feedwater, reactor coolant system (RCS) pressure relief, ATWS mitigating system actuation circuitry (AMSAC), or turbine trip should not be scheduled when an RTB is out of service.	Administrative controls will be implemented within 90 days of NRC approval.
Activities that could degrade the operable train of RPS including master relays, slave relays, and analog channels should not be scheduled concurrently with the out of service train.	Administrative controls will be implemented within 90 days of NRC approval.
Activities on electrical support systems for auxiliary feedwater, RCS pressure relief, AMSAC, or turbine trip should not be scheduled during RTB maintenance.	Administrative controls will be implemented within 90 days of NRC approval.
As part of the implementation of the proposed license amendment, to address a logic cabinet in maintenance, Duke will ensure solid state protection system (SSPS) train and engineered safety features actuation system (ESFAS) train unavailability is included in the Catawba and McGuire Maintenance Rule 10 CFR 50.65(a)(4) program.	Administrative controls will be implemented within 90 days of NRC approval.
Catawba and McGuire will trend as-found and as-left data under the System Health Program for the three representative trip functions analyzed in WCAP-15376 (i.e., OTDT, SG level,	Administrative controls will be implemented within 90 days of NRC approval.

and pressurizer pressure) for two years (four data points) after implementation of the amendment granting 184-day COTs. The data will be trended to evaluate whether the extended frequencies for the affected instruments remain valid.	

ATTACHMENT 6B

TOPICAL REPORT APPLICABILITY DETERMINATION FOR CATAWBA
(NON-PROPRIETARY)

APPLICABILITY OF WCAP-14333-P-A and WCAP-15376-P-A ANALYSES TO CNS

In accordance with the guidance provided in letter WOG-98-245, "Implementation Guideline for WCAP-14333-P-A, Rev. 1 (Proprietary), "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times,"" dated December 2, 1998 (Ref. 4); the information provided in the attached tables demonstrates the applicability of the generic WCAP-14333 analysis to the Catawba Nuclear Station.

In accordance with the guidance provided in letter WOG-03-202, "Transmittal of Approved Topical Report: WCAP-15376-P-A, Rev. 1, (Proprietary) "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times" and Implementation Guidelines (MUHP-3046)," dated April 3, 2003 (Ref. 21); the information in the attached tables demonstrates the applicability of the generic WCAP-15376 analysis to the Catawba Nuclear Station. As suggested in this letter Tables 2 and 3 are for both WCAPs.

WCAP-14333-P-A and WCAP-15376-P-A Condition 1 Analysis:

In order to address this condition Westinghouse issued implementation guidelines for licensees to confirm the analyses are applicable to their plants.

Confirm Applicability:

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McGuire/Catawba Containment Failure Analysis:

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]a,c

WCAP-15376-P-A Condition 3 Analysis (McGuire/Catawba Evaluation of Concurrent Testing on a Logic Cabinet and Associated RTB):

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]a,c

PRA Quality - Catawba

Duke periodically evaluates changes to the plant with respect to the assumptions and modeling in the Catawba PRA. The original Catawba PRA was initiated in July 1984 by Duke Power Company assisted by several outside contractors who performed specialized subtasks. It was a full scope Level 3 PRA with internal and external events. A peer review sponsored by the Electric Power Research Institute (EPRI) was conducted after completion of the draft report. The study was published in an internal Duke report[1] in 1987 as Revision 0 to the PRA.

On November 23, 1988, the NRC issued Generic Letter 88-20[2], which requested that licensees conduct an Individual Plant Examination (IPE) in order to identify potential severe accident vulnerabilities at their plants. The Catawba response to GL 88-20 was provided by letter dated September 10, 1992[3]. Catawba's response included an updated Catawba PRA (Revision 1) study.

The Catawba PRA Revision 1 study and the IPE process resulted in a comprehensive, systematic examination of Catawba with regard to potential severe accidents. The Catawba study was again a full-scope, Level 3 PRA with analysis of both the internal and external events. This examination identified the most likely severe accident sequences, both internally and externally induced, with quantitative perspectives on likelihood and fission product release potential. The results of the study prompted changes in equipment, plant configuration and enhancements in plant procedures to reduce vulnerability of the plant to some accident sequences of concern.

By letter dated June 7, 1994[4], the NRC provided a Safety Evaluation of the internal events portion of the above Catawba IPE submittal. The conclusion of the NRC letter [page 16] states:

> "The staff finds the licensee's IPE submittal for internal events including internal flooding essentially complete, with the level of detail consistent with the information requested in NUREG-1335. Based on the review of the submittal and the associated supporting information, the staff finds reasonable the licensee's IPE conclusion that no fundamental weakness or severe accident vulnerabilities exist at Catawba."

In response to Generic Letter 88-20, Supplement 4, Duke completed an Individual Plant Examination of External Events (IPEEE) for severe accidents. This IPEEE was submitted to the NRC by letter dated June 21, 1994[5]. The report contained a summary of the methods, results and conclusions of the Catawba IPEEE program. The IPEEE process and supporting Catawba PRA included a comprehensive, systematic examination of severe accident potential resulting from external initiating events. By letter dated April 12, 1999[6], the NRC provided an evaluation of the IPEEE submittal. The conclusion of the NRC letter [page 6] states:

"The staff finds the licensee's IPEEE submittal is complete with regard to the information requested by Supplement 4 to GL 88-20 (and associated guidance in NUREG-1407), and the IPEEE results are reasonable given the Catawba design, operation, and history. Therefore, the staff concludes that the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities, and therefore, that the Catawba IPEEE has met the intent of Supplement 4 to GL 88-20."

In 1996, Catawba initiated Revision 2 of the 1992 IPE and provided the results to the NRC in 1998[7]. Since the initial completion of Revision 2, there have been subsequent revisions, 2a, 2b, and 2c which incorporated changes to the model to reflect both plant modifications as well as PRA model enhancements.

Revision 3 of the Catawba PRA was completed in December 2004 and Revision 3a was completed in December 2005. This update is a comprehensive revision to the PRA models and associated documentation. The objectives of this update were as follows:

- To ensure the models comprising the PRA accurately reflect the current plant, including its physical configurations, operating procedures, maintenance practices, etc.
- To review recent operating experience with respect to updating the frequency of plant transients, failure rates, and maintenance unavailability data.
- To correct items identified as errors and implement PRA enhancements as needed.
- To address areas for improvement identified in the recent Catawba PRA Peer Review.
- To utilize updated Common Cause Analysis data and Human Reliability Analysis data.

PRA maintenance encompasses the identification and evaluation of new information into the PRA and typically involves minor modifications to the plant model. PRA maintenance and updates as well as guidance for developing

PRA data and evaluation of plant modifications, are governed by Workplace Procedures.

Approved workplace procedures address the quality assurance of the PRA. One way the quality assurance of the PRA is ensured is by maintaining a set of system notebooks on each of the PRA systems. Each system PRA analyst is responsible for updating a specific system model. A PRA update consists of a comprehensive review of the system including drawings and plant modifications made since the last update as well as implementation of any PRA change notices that may exist on the system. The analyst's primary focal point is with the system engineer at the site. The system engineer provides information for the update as needed. The analyst reviews the PRA model with the system engineer and as necessary, conducts a system walk down with the system engineer.

The system notebooks contain, but are not limited to, documentation on system design, testing and maintenance practices, success criteria, assumptions, descriptions of the reliability data, as well as the results of the quantification. The system notebooks are reviewed and signed off by a second independent person and are approved by the manager of the group.

When any change to the PRA is identified, the same three-signature process of identification, review, and approval is utilized to ensure that the change is valid and that it receives the proper priority.

In January 2001, an enhanced manual configuration control process was implemented to more effectively track, evaluate, and implement PRA changes to better ensure the PRA reflects the as-built, as-operated plant. This process was further enhanced in July 2002 with the implementation of an electronic PRA change tracking tool.

Peer Review Process - Catawba

Between March 18-22, 2002, Catawba participated in the Westinghouse Owners Group (WOG) PRA Certification Program. This review followed a process that was originally developed and used by the Boiling Water Reactor Owners Group (BWROG) and subsequently broadened to be an industry-applicable process through the Nuclear Energy Institute Risk (NEI) Applications Task Force. The resulting industry document, NEI-00-02[8], describes the overall PRA peer review process. The Certification/Peer Review process is also linked to the ASME PRA Standard[9].

The objective of the PRA Peer Review process is to provide a method for establishing the technical quality and adequacy of a PRA for a range of potential risk-informed plant applications for which the PRA may be used. The PRA Peer Review process employs a team of PRA and system analysts, who possess significant expertise in PRA development and PRA applications. The team uses checklists to evaluate the scope, comprehensiveness, completeness, and fidelity of the PRA being reviewed. One of the key parts of the review is an assessment of the maintenance and update process to ensure the PRA reflects the as-built plant.

The review team for the Catawba PRA Peer Review consisted of six members. Three of the members were PRA personnel from other utilities. The remaining three were industry consultants. Reviewer independence was maintained by assuring that none of the six individuals had any involvement in the development of the Catawba PRA or IPE.

A summary of some of the Catawba PRA strengths and recommended areas for improvement from the peer review are as follows:

Strengths

- Aggressive response to past PRA peer reviews
- Knowledgeable personnel
- Culture of continuous improvement
- Documentation of final results and analyses
- Good capture of plant experience into the model
- Rigorous Level 2 and 3 PRA

Recommended Areas for Improvement

- Limited comparison to other plant / utilities PRAs for results and techniques
- Better documentation of bases for success criteria and HRA timing
- More focus on realism vs. conservatism in models
- More attention to eliminating old documentation and modeling assumptions / simplifications
- Consider more efficient methods to streamline recovery / post-processing process

Based on the PRA peer review report, the Catawba PRA received no Fact and Observations (F&O) with the significance level of "A" and 32 F&O with the significance level of "B". The "B" findings have been reviewed and prioritized for incorporation into the PRA. Some of the "B" findings have already been resolved during the normal PRA update process. It is expected that the remaining F&O will be resolved and dispositioned in Revision 4 of the PRA.

The remaining open F&O were reviewed with respect to the impact on the PRA and all were determined to be insignificant with respect to the RPS/ESFAS models.

PRA Model - Catawba

The Catawba PRA is a full scope PRA including both internal and external events. The model includes the necessary initiating events (e.g., LOCAs, transients) to evaluate the frequency of accidents. The previous reviews of the Catawba PRA, NRC and peer reviews have not identified deficiencies related to the scope of initiating events considered.

The Catawba PRA includes models for those systems needed to estimate core damage frequency. These include all of the major support systems (e.g., ac power, service water, component cooling, and instrument air) as well as the mitigating systems (e.g., emergency core cooling). These systems are modeled down to the component level, pumps, valves, and heat exchangers. This level of detail is sufficient for applications.

References - Catawba

1. "Catawba Nuclear Station Unit 1 Probabilistic Risk Assessment," Volumes 1-3, Duke Power Company, August 18, 1987.

2. Generic Letter 88-20, Individual Plant Examination for Severe Accident Vulnerabilities, USNRC, November 1988.

3. Letter Duke Power Company to Document Control Desk (USNRC), Catawba Units 1 and 2, "Individual Plant Examination (IPE) Submittal in Response to Generic Letter 88-20," September 10, 1992.

4. Letter USNRC to Duke Power Company, "Safety Evaluation of Catawba Nuclear Station, Units 1 and 2 Individual Plant Examination (IPE) Submittal," June 7, 1994.

5. Letter Duke Power Company to Document Control Desk (USNRC), Catawba Units 1 and 2, "Individual Plant Examination of External Events (IPEEE) Submittal," June 21, 1994.

6. Letter USNRC to Duke Power Company, "CATAWBA NUCLEAR STATION -- REVIEW OF INDIVIDUAL PLANT EXAMINATION OF EXTERNAL EVENTS (IPEEE)," April 12, 1999.

7. Letter Duke Energy Corporation to Document Control Desk (USNRC), Catawba Units 1 and 2, "Probabilistic Risk Assessment (PRA), Revision 2 Summary Report, January 1998."

8. NEI-00-02, "Probabilistic Risk Assessment (PRA) Peer Review Process Guideline," Nuclear Energy Institute, March 2000.

9. "Standard For Probabilistic Risk Assessment for Nuclear Power Plant Applications," ASME RA-S-2002, January 31, 2002, ASME RA-Sa-2003 Addenda, December 2003, and ASME RA-Sb-2005 Addenda, December 2005.

Justification of the use of LERF-to-CDF Ratio

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Conclusion

Duke assessments of the topical report and of postulated containment failures confirm that WCAP-15376-P is applicable to the design and operation of Catawba.

NON-PROPRIETARY

Table 1

WCAP-14333 Implementation Guidelines: Applicability of the Analysis General Parameters

Parameter	WCAP-14333 Analysis Assumptions	Plant Specific Parameter
Logic Cabinet Type (1)	Relay and SSPS	SSPS
Component Test Intervals (2)		
• Analog Channels	3 months	92 days
• Logic Cabinets (SSPS)	2 months	31 Days (Staggered Test Basis)
• Logic Cabinets (Relay)	1 month	NA
• Master Relays (SSPS)	2 months	31 Days (Staggered Test Basis)
• Master Relays (Relay)	1 month	NA
• Slave Relays	3 months	92 days
• Reactor Trip Breakers	2 months	31 Days (Staggered Test Basis)
Analog Channel Calibrations (3)		
• Done at-power	Yes	Yes
• Interval	18 months	18 months
Typical At-Power Maintenance Intervals (4)		
• Analog Channels	24 months	Equal to or Greater Than
• Logic Cabinets (SSPS)	18 months	Equal to or Greater Than
• Logic Cabinets (Relay)	12 months	NA
• Master Relays (SSPS)	infrequent (5)	Infrequent
• Master Relays (Relay)	infrequent (5)	NA
• Slave Relays	infrequent (5)	Infrequent
• Reactor trip breakers	12 months	Equal to or Greater Than
AMSAC (6)	Credited for AFW pump start	Yes, provides AFW pump start
Total Transient Event Frequency (7)	3.6	0.7 events/reactor year
ATWS Contribution to CDF (current PRA model) (8)	8.4E-06	8.6E-08 /reactor year
Total CDF from Internal Events (current PRA model) (9)	5.8E-05	1.6E-05 /reactor year
Total CDF from Internal Events (IPE) (10)	Not Applicable	7.9E-05 /reactor year

NON-PROPRIETARY

Notes for Table 1

1. Indicate type of logic cabinet; SSPS or Relay (both are included in WCAP-14333).
2. Fill in applicable test intervals. If the test intervals are equal to or greater than those used in WCAP-14333, the analysis is applicable to your plant.
3. Indicate if channel calibration is done at-power and, if so, fill in the interval. If channel calibrations are not done at-power or if the calibration interval is equal to or greater than that used in WCAP-14333, the analysis is applicable to your plant.
4. Fill in the applicable typical maintenance intervals or fill in "equal to or greater than" or "less than". If the maintenance intervals are equal to or greater than those used in WCAP-14333, the analysis is applicable to your plant.
5. Only corrective maintenance is done on the master and slave relays. The maintenance interval on typical relays is relatively long, that is, experience has shown they do not typically completely fail. Failure of slave relays usually involve failure of individual contacts. Fill in "infrequent" if this is consistent with your plant experience. If not, fill in the typical maintenance interval. If "infrequent" slave relay failures are the norm, then the WCAP-14333 analysis is applicable to your plant.
6. The Catawba AMSAC design will initiate AFW pump start for the Motor Driven AFW pumps; therefore the WCAP-14333 analysis is applicable to Catawba. However, the Catawba PRA does not credit this AMSAC function due to expected small contribution to core damage frequency.
7. Includes the total frequency for internal initiators requiring a reactor trip signal to be generated for event mitigation. This is required to assess the importance of ATWS events to CDF. Does not include events initiated by a reactor trip (i.e. reactor trip initiating event frequency is excluded).
8. Indicates the ATWS contribution to core damage frequency (from at-power, internal events). This is required to determine if the ATWS event is a large contributor to CDF.
9. Indicates the total CDF from internal events (including internal flooding) for the most recent PRA model update. This is required for comparison to the NRC's risk-informed CDF acceptance guidelines.
10. Indicates the total CDF from internal events from the IPE model (submitted to the NRC in response to Generic Letter 88-20). These values differ from the most recent PRA model update CDF so a concise list of reasons, in bulletized form, describing the differences between the models that account for the change in CDF, is provided. (See below)

Plant model changes for Catawba Nuclear Station since IPE:

- Added backup cooling to the high head safety injection centrifugal charging pump A.
- Floodwall surrounding 4160 VAC transformers in turbine building basement.
- Overall model component and logic review and update.
- Updated human error reliability data.
- Updated common cause data.
- Updated plant specific data.
- Updated initiating event frequencies.
- Updated system notebooks.
- Updated generic data.
- Implemented new reactor coolant seal model.

11. If your analog channel test interval is 1 month, the STI increase justified and approved by the NRC in WCAP-10271 has not been implemented in your plant; even so, this analysis still remains applicable.

NON-PROPRIETARY

Table 2

WCAP-15376 Implementation Guidelines:

Applicability of the Analysis General Parameters

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NON-PROPRIETARY

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NON-PROPRIETARY

Table 3

WCAP-14333 and WCAP-15376 Implementation Guidelines:
Applicability of Analysis Reactor Trip Actuation Signals

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NON-PROPRIETARY

Table 4

WCAP-14333 and WCAP-15376 Implementation Guidelines:
Applicability of Analysis Engineered Safety Features Actuation Signals

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NON-PROPRIETARY

Table 5
WCAP-15376 Implementation Guidelines:
Applicability of the Human Reliability Analysis

a,c

ATTACHMENT 7B

TOPICAL REPORT APPLICABILITY DETERMINATION FOR MCGUIRE
(NON-PROPRIETARY)

APPLICABILITY OF WCAP-14333-P-A and WCAP-15376-P-A ANALYSES TO MNS

In accordance with the guidance provided in letter WOG-98-245, "Implementation Guideline for WCAP-14333-P-A, Rev. 1 (Proprietary), "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times,"" dated December 2, 1998 (Ref. 4); the information provided in the attached tables demonstrates the applicability of the generic WCAP-14333 analysis to the McGuire Nuclear Station.

In accordance with the guidance provided in letter WOG-03-202, "Transmittal of Approved Topical Report: WCAP-15376-P-A, Rev. 1, (Proprietary) "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times" and Implementation Guidelines (MUHP-3046)," dated April 3, 2003 (Ref. 21); the information in the attached tables demonstrates the applicability of the generic WCAP-15376 analysis to the McGuire Nuclear Station. As suggested in this letter Tables 2 and 3 are for both WCAPs.

<u>WCAP-14333-P-A and WCAP-15376-P-A Condition 1 Analysis:</u>

In order to address this condition Westinghouse issued implementation guidelines for licensees to confirm the analyses are applicable to their plants.

<u>Confirm Applicability:</u>

[

]a,c

PRA Quality - McGuire

Duke periodically evaluates changes to the plant with respect to the assumptions and modeling in the McGuire PRA. The original McGuire PRA was initiated in March 1982 by Duke Power Company staff with Technology for Energy Corporation as a contractor. Law Engineering Testing Company and Structural Mechanics Associates provided specific input to the seismic analysis. It was a full scope Level 3 PRA with internal and external events. A peer review of the draft PRA was conducted by Electric Power Research Institute's Nuclear Safety Analysis Center (NSAC) in May 1983[1]. The final study, which incorporated the comments of the peer review, was completed in July 1984 and resulted in an internal Duke report[2] as Revision 0 to the PRA. In January 1988, Duke Power Company initiated a complete review and update of the original study.

On November 23, 1988, the NRC issued Generic Letter 88-20[3], which requested that licensees conduct an Individual Plant Examination (IPE) in order to identify potential severe accident vulnerabilities at their plants. The McGuire response to GL 88-20 was provided by letter dated November 4, 1991[4]. McGuire's response included an updated McGuire PRA (Revision 1) study which was the culmination of the review and update which began in January 1988.

The McGuire PRA Revision 1 study and the IPE process resulted in a comprehensive, systematic examination of McGuire with regard to potential severe accidents. The McGuire study was again a full-scope, Level 3 PRA with analysis of both the internal and external events. This examination identified the most likely severe accident sequences, both internally and externally induced, with quantitative perspectives on likelihood and fission product release potential. The results of the study prompted changes in equipment, plant configuration and enhancements in plant procedures to reduce vulnerability of the plant to some accident sequences of concern.

As part of the Generic Letter 88-20 IPE process, the NRC conducted an audit of the human reliability analysis of the McGuire IPE during the period July 28 - 30, 1993. By letter dated June 30, 1994[5], the NRC provided a Staff Evaluation of the internal events portion of the above McGuire IPE submittal which included the results of the human reliability analysis audit. The conclusion of the NRC letter [page 15] states:

> "The staff finds the licensee's IPE submittal for internal events including internal flooding essentially complete, with the level of detail consistent with the information requested in NUREG-1335. Based on the review of the submittal, and audit of "tier 2" supporting information, the staff finds

> reasonable the licensee's IPE conclusion that no severe accident vulnerabilities exist at McGuire."

In response to Generic Letter 88-20, Supplement 4, Duke completed an Individual Plant Examination of External Events (IPEEE) for severe accidents. This IPEEE was submitted to the NRC by letter dated June 1, 1994[6]. The report contained a summary of the methods, results and conclusions of the McGuire IPEEE program. The IPEEE process and supporting McGuire PRA included a comprehensive, systematic examination of severe accident potential resulting from external initiating events. By letter dated February 16, 1999[7], the NRC provided an evaluation of the IPEEE submittal. The conclusion of the NRC letter [page 6] states:

> "On the basis of the overall review findings, the staff concludes that: (1) the licensee's IPEEE is complete with regard to the information requested by Supplement 4 to GL 88-20 (and associated guidance in NUREG-1407), and (2) the IPEEE results are reasonable given the MNS design, operation, and history. Therefore, the staff concludes that the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities, and therefore, that the MNS IPEEE has met the intent of Supplement 4 to GL 88-20 and the resolution of specific generic safety issues discussed in the SER."

In 1997, McGuire initiated Revision 2 of the 1991 IPE and provided the results to the NRC in 1998[8]. Revision 3 of the McGuire PRA was completed in July 2002 and Revision 3a was completed in February 2005. Revision 3 was a comprehensive revision to the PRA models and associated documentation. The objectives of this update were as follows:

- To ensure the models comprising the PRA accurately reflect the current plant, including its physical configurations, operating procedures, maintenance practices, etc.
- To review recent operating experience with respect to updating the frequency of plant transients, failure rates, and maintenance unavailability data.
- To correct items identified as errors and implement PRA enhancements as needed.
- To address areas for improvement identified in the recent McGuire PRA Peer Review.

- To utilize updated Common Cause Analysis data and Human Reliability Analysis data.

PRA maintenance encompasses the identification and evaluation of new information into the PRA and typically involves minor modifications to the plant model. PRA maintenance and updates as well as guidance for developing PRA data and evaluation of plant modifications, are governed by Workplace Procedures.

Approved workplace procedures address the quality assurance of the PRA. One way the quality assurance of the PRA is ensured is by maintaining a set of system notebooks on each of the PRA systems. Each system PRA analyst is responsible for updating a specific system model. A PRA update consists of a comprehensive review of the system including drawings and plant modifications made since the last update as well as implementation of any PRA change notices that may exist on the system. The analyst's primary focal point is with the system engineer at the site. The system engineer provides information for the update as needed. The analyst reviews the PRA model with the system engineer and as necessary, conducts a system walkdown with the system engineer.

The system notebooks contain, but are not limited to, documentation on system design, testing and maintenance practices, success criteria, assumptions, descriptions of the reliability data, as well as the results of the quantification. The system notebooks are reviewed and signed off by a second independent person and are approved by the manager of the group.

When any change to the PRA is identified, the same three-signature process of identification, review, and approval is utilized to ensure that the change is valid and that it receives the proper priority.

In January 2001, an enhanced manual configuration control process was implemented to more effectively track, evaluate, and implement PRA changes to better ensure the PRA reflects the as-built, as-operated plant. This process was further enhanced in July 2002 with the implementation of an electronic PRA change tracking tool.

Peer Review Process - McGuire

Between October 23-27, 2000, McGuire participated in the Westinghouse Owners Group (WOG) PRA Certification Program. This review followed a process that was originally developed and used by the Boiling Water Reactor Owners Group (BWROG) and subsequently broadened to be an industry-applicable process through the Nuclear Energy Institute (NEI) Risk Applications Task Force. The resulting industry document, NEI-00-02[9], describes the overall PRA peer review process. The Certification/Peer Review process is also linked to the ASME PRA Standard[10].

The objective of the PRA Peer Review process is to provide a method for establishing the technical quality and adequacy of a PRA for a range of potential risk-informed plant applications for which the PRA may be used. The PRA Peer Review process employs a team of PRA and system analysts, who possess significant expertise in PRA development and PRA applications. The team uses checklists to evaluate the scope, comprehensiveness, completeness, and fidelity of the PRA being reviewed. One of the key parts of the review is an assessment of the maintenance and update process to ensure the PRA reflects the as-built plant.

The review team for the McGuire PRA Peer Review consisted of six members. Three of the members were PRA personnel from other utilities. The remaining three were industry consultants. Reviewer independence was maintained by assuring that none of the six individuals had any involvement in the development of the McGuire PRA or IPE.

A summary of some of the McGuire PRA strengths and recommended areas for improvement from the peer review are as follows:

Strengths

- Good Summary Report write-up with insights
- Good system notebooks
- Rigorous Level 2 & 3 PRA Model
- Integrated internal and external events model
- Up-to-date plant database using Maintenance Rule
- Ongoing PRA staff interaction with plant staff, plant staff reviews
- PRA personnel knowledge of plant good

Recommended Areas for Improvement

- Better integration of sequences and recoveries within quantification process needed
- Need to review treatment of events requiring time-phasing in the modeling
- Better approach to closing the loop on PRA update items (tracking of errors/mods) needed
- More thorough, systematic approach to HRA screening values and common cause modeling needed
- Need an approach for reconciling realistic LERF model with NRC expectations from simplistic LERF modeling

- Need to update the PRA model to be more in line with current practices and expectations for state-of-the-art PRA

Based on the PRA peer review report, the McGuire PRA received six Fact and Observations (F&O) with the significance level of "A" and 31 F&O with the significance level of "B". All six of the "A" F&O have been resolved and changes have been incorporated into McGuire PRA Revision 3, the current PRA model. The "B" F&O have been reviewed and prioritized for incorporation into the PRA. Some of the "B" F&O have already been resolved during the normal PRA update process. It is expected that the remaining F&O will be resolved and dispositioned in Revision 4 of the PRA.

The remaining open F&O were reviewed with respect to the impact on the PRA and were determined to be insignificant with respect to the RPS/ESFAS models with one possible exception. The peer review team commented that there were no pre-initiator human interactions in the PRA for modeling instrument miscalibration events and suggested that either the basis for excluding miscalibration events be documented or appropriate events should be developed for inclusion in the PRA model.

Adding latent human error (LHE) interactions into the PRA for miscalibration events was examined qualitatively for any impact on the RPS/ESFAS models. The effect of the addition of LHE interactions in the RPS/ESFAS models would be to increase the failure probability and system unavailability of these systems which would have a very small impact on the overall CDF value. However, increasing the failure probability should lower the importance of the maintenance unavailability of RPS/ESFAS components by reducing its overall contribution to the failure probability of RPS/ESFAS components. Therefore it is expected that any LHE additions to the RPS/ESFAS models would also have an insignificant impact and would not invalidate the conclusions of WCAP-15376-P.

PRA Model - McGuire

The McGuire PRA is a full scope PRA including both internal and external events. The model includes the necessary initiating events (e.g., LOCAs, transients) to evaluate the frequency of accidents. The previous reviews of the McGuire PRA, NRC and peer reviews, have not identified deficiencies related to the scope of initiating events considered.

The McGuire PRA includes models for those systems needed to estimate core damage frequency. These include all of the major support systems (e.g., ac power, service water, component cooling, and instrument air) as well as the mitigating systems (e.g., emergency core cooling). These systems are modeled down to the component level, pumps, valves, and heat exchangers. This level of detail is sufficient for applications.

References - McGuire

1. Nuclear Safety Analysis Center, "McGuire Unit 1 PRA Peer Review," May 27, 1983.

2. "McGuire Nuclear Station Unit 1 Probabilistic Risk Assessment," Volumes 1-2, Duke Power Company, July 1984.

3. Generic Letter 88-20, Individual Plant Examination for Severe Accident Vulnerabilities, USNRC, November 1988.

4. Letter Duke Power Company to Document Control Desk (USNRC), McGuire Nuclear Station, "Generic Letter 88-20," November 4, 1991.

5. Letter USNRC to Duke Power Company, "Staff Evaluation of the McGuire Nuclear Station, Units 1 and 2 Individual Plant Examination - Internal Events Only," June 30, 1994.

6. Letter Duke Power Company to Document Control Desk (USNRC), McGuire Nuclear Station, Units 1 and 2, "Individual Plant Examination of External Events (IPEEE) Submittal," June 1, 1994.

7. Letter USNRC to Duke Power Company, "REVIEW OF MCGUIRE NUCLEAR STATION, UNITS 1 AND 2 - INDIVIDUAL PLANT EXAMINATION OF EXTERNAL EVENTS SUBMITTAL," February 16, 1999.

8. Letter Duke Energy Corporation to Document Control Desk (USNRC), McGuire Nuclear Station, "1997 Update of Probabilistic Risk Assessment," March 19, 1998.

9. NEI-00-02, "Probabilistic Risk Assessment (PRA) Peer Review Process Guideline," Nuclear Energy Institute, March 2000.

10. "Standard For Probabilistic Risk Assessment for Nuclear Power Plant Applications," ASME RA-S-2002, January 31, 2002, ASME RA-Sa-2003 Addenda, December 2003, and ASME RA-Sb-2005 Addenda, December 2005.

Justification of the use of LERF-to-CDF Ratio

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Conclusion

Duke assessments of the topical report and of postulated containment failures confirm that WCAP-15376-P is applicable to the design and operation of McGuire.

Table 1
WCAP-14333 Implementation Guidelines:
Applicability of the Analysis General Parameters

Parameter	WCAP-14333 Analysis Assumptions	Plant Specific Parameter
Logic Cabinet Type (1)	Relay and SSPS	SSPS
Component Test Intervals (2)		
• Analog Channels	3 months	3 months
• Logic Cabinets (SSPS)	2 months	2 months
• Logic Cabinets (Relay)	1 month	NA
• Master Relays (SSPS)	2 months	2 months
• Master Relays (Relay)	1 month	NA
• Slave Relays	3 months	3 months
• Reactor Trip Breakers	2 months	2 months
Analog Channel Calibrations (3)		
• Done at-power	Yes	Yes
• Interval	18 months	Equal to or greater than
Typical At-Power Maintenance Intervals (4)		
• Analog Channels	24 months	Equal to or greater than
• Logic Cabinets (SSPS)	18 months	Equal to or greater than
• Logic Cabinets (Relay)	12 months	NA
• Master Relays (SSPS)	infrequent (5)	Infrequent
• Master Relays (Relay)	infrequent (5)	NA
• Slave Relays	infrequent (5)	Infrequent
• Reactor trip breakers	12 months	Equal to or greater than
AMSAC (6)	Credited for AFW pump start	Yes, provides AFW pump start
Total Transient Event Frequency (7)	3.6	0.9 events/reactor year
ATWS Contribution to CDF (current PRA model) (8)	8.4E-06	5.8E-07/reactor year
Total CDF from Internal Events (current PRA model) (9)	5.8E-05	2.2E-05/reactor year
Total CDF from Internal Events (IPE) (10)	Not Applicable	5.6E-06/reactor year

Notes for Table 1

1. Indicate type of logic cabinet; SSPS or Relay (both are included in WCAP-14333).
2. Fill in applicable test intervals. If the test intervals are equal to or greater than those used in WCAP-14333, the analysis is applicable to your plant.
3. Indicate if channel calibration is done at-power and, if so, fill in the interval. If channel calibrations are not done at-power or if the calibration interval is equal to or greater than that used in WCAP-14333, the analysis is applicable to your plant.
4. Fill in the applicable typical maintenance intervals or fill in "equal to or greater than" or "less than". If the maintenance intervals are equal to or greater than those used in WCAP-14333, the analysis is applicable to your plant.
5. Only corrective maintenance is done on the master and slave relays. The maintenance interval on typical relays is relatively long, that is, experience has shown they do not typically completely fail. Failure of slave relays usually involves failure of individual contacts. Fill in "infrequent" if this is consistent with your plant experience. If not, fill in the typical maintenance interval. If "infrequent" slave relay failures are the norm, then the WCAP-14333 analysis is applicable to your plant.
6. The McGuire AMSAC design will initiate AFW pump start for the Motor Driven AFW pumps; therefore then the WCAP-14333 analysis is applicable to McGuire. However, the McGuire PRA does not credit this AMSAC function due to expected small contribution to core damage frequency.
7. Includes total frequency for initiators requiring a reactor trip signal to be generated for event mitigation. This is required to assess the importance of ATWS events to CDF. Does not include events initiated by a reactor trip (i.e. reactor trip initiating event frequency is excluded).
8. Indicates the ATWS contribution to core damage frequency (from at-power, internal events). This is required to determine if the ATWS event is a large contributor to CDF.
9. Indicates the total CDF from internal events (including internal flooding) for the most recent PRA model update. This is required for comparison to the NRC's risk-informed CDF acceptance guidelines.
10. Indicates the total CDF from internal events from the IPE model (submitted to the NRC in response to Generic Letter 88-20). If this value differs from the most recent PRA model update CDF provide a concise list of reasons, in bulletized form, describing the differences between the models that account for the change in CDF. (See Below)

Plant model changes for McGuire Nuclear Station since IPE:

- Overall model component and logic review and update.
- Updated human error reliability data.
- Updated common cause data.
- Updated plant specific data.
- Updated initiating event frequencies.
- Updated system notebooks.
- Updated generic data.
- Implemented new reactor coolant seal model

NON-PROPRIETARY

11. If your analog channel test interval is 1 month, the STI increase justified and approved by the NRC in WCAP-10271 has not been implemented in your plant; even so, this analysis still remains applicable.

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Table 2
WCAP-15376 Implementation Guidelines:
Applicability of the Analysis General Parameters

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Table 3
WCAP-14333 and WCAP-15376 Implementation Guidelines: Applicability of Analysis Reactor Trip Actuation Signals

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Table 4
WCAP-14333 and WCAP-15376 Implementation Guidelines:
Applicability of Analysis Engineered Safety Features Actuation Signals

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Table 5
WCAP-15376 Implementation Guidelines:
Applicability of the Human Reliability Analysis

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