FENOC

FirstEnergy Nuclear Operating Company

Peter P. Sena III
Site Vice President

724-682-5234
Fax: 724-643-8069

December 21, 2007
L-07-515

10 CFR 50.90

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

SUBJECT:
Beaver Valley Power Station, Unit Nos. 1 and 2
BV-1 Docket No. 50-334, License No. DPR-66
BV-2 Docket No. 50-412, License No. NPF-73
License Amendment Request Number 07-005

Pursuant to 10 CFR 50.90, FirstEnergy Nuclear Operating Company (FENOC) hereby requests the following amendments:

These amendment applications incorporate changes contained in Technical Specification Task Force (TSTF) 411, Revision 1, "Surveillance Test Interval Extensions for Components of the Reactor Protection System (WCAP-15376)," (Reference 1) and TSTF 418, Revision 2, "RPS and ESFAS Test Times and Completion Times (WCAP-14333)," (Reference 2). The changes are achieved through the implementation of WCAP-14333-P-A, Revision 1 (Reference 3) and WCAP-15376-P-A, Revision 1 (Reference 4). The changes involve relaxation of Reactor Trip System (RTS) and Engineered Safety Features Actuation Signal (ESFAS) Instrumentation bypass test times, Completion Times, and Surveillance Frequencies for various instrumentation.

Enclosure 1 contains the evaluation of the proposed changes. This enclosure also contains markups of the Technical Specifications and Bases. The Bases changes are provided for information only.

Enclosure 2 contains Affidavit CAW-07-2309 and the request to withhold the proprietary information from public disclosure.

Enclosure 3 contains WCAP-15376 Implementation Guideline, "Approach to Address the Conditions and Limitations in the NRC's Safety Evaluation" (Proprietary).

Enclosure 4 contains WCAP-15376 Implementation Guideline, "Approach to Address the Conditions and Limitations in the NRC's Safety Evaluation" (Non-Proprietary).

A001
NRR

As Enclosure 3 contains information proprietary to Westinghouse Electric Company LLC, it is 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 Section 2.390 of the Commission's regulations. The affidavit, along with a Westinghouse authorization letter (CAW-07-2309), Proprietary Information Notice, and Copyright Notice is provided in Enclosure 2. Accordingly, it is respectfully requested that the information proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR Section 2.390 of the Commission's regulations.

Correspondence with respect to the copyright or proprietary aspects of Enclosures 3 and 4, or the supporting Westinghouse Affidavit, should reference CAW-07-2309 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

These applications are risk-informed and the guidance in Regulatory Guides 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," (Reference 5) and 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specification" (Reference 6) has been followed.

These changes have been reviewed by the Beaver Valley Power Station review committees. The changes were determined to be safe and do not involve a significant hazard consideration as defined in 10 CFR 50.92 based on the attached safety analysis and no significant hazard evaluation.

FENOC requests approval of the proposed amendments by December 2008. Once approved, the amendments shall be implemented within 90 days.

The regulatory commitments contained in this letter are listed in Attachment A. If there are any questions or if additional information is required, please contact Mr. Thomas A. Lentz, Manager – FENOC Fleet Licensing, at 330-761-6071.

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

Sincerely,

Peter P. Sena III

Attachment:
A. Regulatory Commitment List

Enclosures:
1. FENOC Evaluation of the Proposed Changes
2. Affidavit CAW-07-2309
3. WCAP-15376 Implementation Guideline, "Approach to Address the Conditions and Limitations in the NRC's Safety Evaluation" (Proprietary)
4. WCAP-15376 Implementation Guideline, "Approach to Address the Conditions and Limitations in the NRC's Safety Evaluation" (Non-Proprietary)

References:
1. Technical Specification Task Force Traveler, TSTF-411, Revision 1, "Surveillance Test Interval Extensions for Components of the Reactor Protection System (WCAP-15376)."
2. Technical Specification Task Force Traveler, TSTF-418, Revision 2, "RPS and ESFAS Test Times and Completion Times (WCAP-14333)."
3. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.
4. 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.
5. Regulatory Guide 1.174 "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis."
6. Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specification."

cc: Mr. S. J. Collins, NRC Region I Administrator
Mr. D. L. Werkheiser, NRC Senior Resident Inspector
Ms. N. S. Morgan, NRR Project Manager
Mr. D. J. Allard, Director BRP/DEP
Mr. L. E. Ryan (BRP/DEP)

ATTACHMENT A
L-07-515

Regulatory Commitment List

The following list identifies those actions committed to by FirstEnergy Nuclear Operating Company (FENOC) for Beaver Valley Power Station (BVPS) Unit Nos. 1 and 2 in this document. Any other actions discussed in the submittal represent intended or planned actions by FENOC. They are described only as information and are not Regulatory Commitments. Please notify Mr. Thomas A. Lentz, Manager - Licensing, at (330) 761-6071 of any questions regarding this document or associated Regulatory Commitments.

Regulatory Commitment	Due Date
1. FENOC will review applicable BVPS programs and revise them as necessary to ensure that the intent of the RTS and ESFAS equipment unavailability and component failure modeling assumptions in WCAP 14333 and WCAP 15376 are met at BVPS	Prior to, or concurrent with, amendment implementation.

ENCLOSURE 1
FENOC Evaluation of the Proposed Changes

Beaver Valley Power Station
License Amendment Request 07-005 (Units 1 and 2)

Subject: Implementation of WCAP-14333-P-A, Revision 1 and WCAP-15376-P-A, Revision 1

Table of Contents

Section	Title	Page
1.0	SUMMARY DESCRIPTION	1
2.0	DETAILED DESCRIPTION	5
2.1	Pending License Amendment Requests	5
2.2	Proposed Technical Specifications Changes	6
3.0	TECHNICAL EVALUATION	10
4.0	REGULATORY EVALUATION	40
4.1	Significant Hazards Consideration	40
4.2	Applicable Regulatory Requirements/Criteria	45
4.3	Precedent	47
4.4	Conclusions	48
5.0	ENVIRONMENTAL CONSIDERATION	49
6.0	REFERENCES	49

Attachments

Number	Title
A	Proposed Technical Specification Changes
B	Proposed Technical Specification Bases Changes

1.0 SUMMARY DESCRIPTION

This is a request to amend Operating Licenses DPR-66 (Beaver Valley Power Station Unit 1) and NPF-73 (Beaver Valley Power Station Unit 2).

Beaver Valley Power Station (BVPS) Technical Specifications 3.3.1, Reactor Trip System (RTS) Instrumentation, Technical Specification 3.3.2, Engineered Safety Feature Actuation System (ESFAS) Instrumentation, and Technical Specification 3.3.5, Loss of Power (LOP) Diesel Generator (DG) Start and Bus Separation Instrumentation are being revised to adopt the bypass test time, Completion Time, and Surveillance Frequency changes approved by NRC in WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998 (Reference 1) and 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 (Reference 2). This amendment application incorporates changes contained in the following NRC-approved travelers: Industry/Technical Specification Task Force (TSTF) Standard Technical Specifications (STS) Change Traveler 411, Revision 1, "Surveillance Test Interval Extensions for Components of the Reactor Protection System (WCAP-15376)," (Reference 3) and Industry/TSTF STS Change Traveler 418, Revision 2, "RPS and ESFAS Test Times and Completion Times (WCAP-14333)," (Reference 4). All references cited in this Evaluation are listed in Section 6.0. The AOT acronym and the term "Completion Time," which is utilized in NUREG-1431, are synonymous.

Over the past several years the Westinghouse Owners Group (WOG) (now called the Pressurized Water Reactor Owners Group or PWROG) completed a series of topical reports that document the relaxation of RTS and ESFAS bypass test times, Completion Times, and Surveillance Frequencies for the protection system instrumentation. The relaxations were justified by an analysis of the protection system reliability and the impact of that reliability on the overall plant risk. The original study was identified by the acronym TOP (taken from Technical Specification Optimization Program) as documented in the WCAP-10271-P-A series of topical reports. The changes contained in the WCAP-10271-P-A series of

topical reports were implemented at the Beaver Valley Power Station by License Amendments 181 for Unit 1 and 61 for Unit 2 (Reference 5). When reviewing the risk metric results, the BVPS current licensing basis is that of a "TOP" plant.

Fault tree models of the protection system instrumentation were used to calculate changes in signal unavailability resulting from changes to test and maintenance time allowances and frequencies. The changes in RTS and ESFAS signal unavailability were then used in a risk model to assess the risk impact as the test and maintenance time allowances and frequencies were relaxed. Differences in analysis methods from the TOP WCAP-10271-P-A (hereafter referred to as WCAP-10271) series of reports are discussed in Section 7.1 of WCAP-14333-P-A, Revision 1 (hereafter referred to as WCAP-14333) and in Section 8.3.3 of WCAP-15376-P-A, Revision 1 (hereafter referred to as WCAP-15376).

The approach used in WCAP-14333 and WCAP-15376 is consistent with the approach established in the TOP. This generally includes the fault tree models, signals, component reliability database, test and maintenance assumptions, and risk model. The methodology in WCAP-14333 used a representative set of RTS and ESFAS signals to determine the impact of the proposed changes on signal unavailability, and used a representative Probabilistic Risk Assessment (PRA) model to determine the impact on core damage frequency (CDF) and large early release frequency (LERF). Incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) evaluations were also completed, consistent with Regulatory Guides 1.174 "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specification." In comparison to WCAP-10271, WCAP-14333 used a different common cause failure modeling approach for analog channels and included more realistic assumptions related to the component unavailability due to maintenance activities based on a survey of WOG plants. Operator actions to either manually trip the reactor or initiate safety injection were also modeled in WCAP-14333. In addition, credit for auxiliary feedwater pump start from the anticipated transient without

scram (ATWS) mitigating system actuation circuitry (AMSAC) was taken. More discussion of these differences is contained in Sections 7 and 8 of WCAP-14333. The relaxations that are justified in WCAP-14333 are summarized in Table 1.

Table 1 Summary of WCAP-14333 RTS and ESFAS Completion Time and Bypass Test Time Changes Solid State Protection System		
Component	Completion Time	Bypass Test Time
Analog channels	6+6 hours to 72+6 hours	4 hours to 12 hours
Logic train	6+6 hours to 24+6 hours	no relaxation*
Actuation relays	6+6 hours to 24+6 hours	no relaxation*
* - no relaxation beyond TOP (WCAP-10271 and its supplements)		

The NRC issued a Safety Evaluation on July 15, 1998 approving WCAP-14333. The improvements identified in WCAP-14333 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.

Southern Nuclear Company (SNC) submitted a License Amendment Request (LAR) on October 13, 1999 for the Vogtle Units 1 and 2 to adopt the relaxations that were generically approved in WCAP-14333. In response to an NRC request for additional information (RAI) on the SNC LAR, incremental conditional large early release probability (ICLERP) values were calculated that are generically

applicable to all WOG plants. The SNC LAR correspondence is identified in Reference 6. Amendments 116 and 94 were issued for Vogtle Units 1 and 2 approving the changes justified in WCAP-14333.

The NRC issued a Safety Evaluation on December 20, 2002 approving WCAP-15376. WCAP-15376 expanded upon the groundwork laid by WCAP-14333, but used updated component failure probability data (WCAP-15376, Section 8.2) and made some changes to the fault tree models (WCAP-15376, Section 8.3). Using these modifications, the changes previously approved in WCAP-14333 were quantified as the base case for WCAP-15376. Section 8.4 of WCAP-15376 provides the risk metrics for the changes and demonstrates that the acceptance criteria of Regulatory Guide 1.174 and Regulatory Guide 1.177 are satisfied.

WCAP-15376 provides the technical justification for the RTS Instrumentation (Technical Specification 3.3.1) and ESFAS Instrumentation (Technical Specification 3.3.2) Technical Specification changes listed in Table 2 that are being proposed.

Table 2
Summary of WCAP-15376 RTS and ESFAS Surveillance Frequencies and Completion Time (CT) Changes
Solid State Protection System

Component	Surveillance Frequencies	Completion Times and Bypass Times
Logic Train	2 months to 6 months	No changes
Master Relays	2 months to 6 months	No changes
Analog Channels	3 months to 6 months	No changes
Reactor Trip Breakers	2 months to 4 months	CT: 1 hour to 24 hours Bypass Time: 2 hours to 4 hours

2.0 DETAILED DESCRIPTION

The proposed Technical Specification changes, which are submitted for NRC review and approval, are provided in Attachment A[1] for BVPS Units 1 and 2. The changes proposed to the Technical Specification Bases are provided in Attachment B for Units 1 and 2. The proposed Technical Specification Bases changes do not require NRC approval. The BVPS Technical Specification Bases Control Program controls the review, approval and implementation of Technical Specification Bases changes. The Technical Specification Bases changes are provided for information only.

To meet format requirements the Index, Technical Specifications and Technical Specification Bases pages will be revised and repaginated as necessary to reflect the changes being proposed by this License Amendment Request (LAR).

2.1 Pending License Amendment Requests

On February 9, 2007 (Reference 7) FENOC submitted LAR Nos. 334 and 205 that contain Technical Specification changes that are related to the Technical Specification changes proposed in this LAR. The changes proposed in Reference 7 add a new ESFAS Function (2.b) to Table 3.3.2-1 for the Recirculation Spray System (RSS) due to a modification to the containment sump screens. Function 2.b is added because the containment sump modification required a change to the ESFAS start signal for the RSS pumps. Although Reference 7 changes Technical Specification pages in Section 3.3, none of these pages are changed by this LAR.

The application of the Completion Time and Surveillance Frequency extensions proposed in this LAR to the new ESFAS Function 2.b (coincident with a Containment Pressure High-High/RWST Level Low ESFAS signal) is justified in

---

[1] The proposed changes to the Technical Specifications and Technical Specification Bases have been prepared electronically. Deletions are shown with a strike-through and insertions are shown double-underlined. This presentation allows the reviewer to readily identify the information that has been deleted and added.

Section 3.0 of this LAR. Since this new ESFAS Function is a plant specific signal and is not addressed by the WCAP-10271-P-A series of topical reports, WCAP-14333-P-A, Revision 1 or WCAP-15376-P-A, Revision 1, a plant specific justification is provided in Section 3.0 of this LAR.

2.2 Proposed Technical Specifications Changes

Changes to the following Technical Specifications (TS) are being proposed.

CHANGE	TS	TITLE
1	3.3.1	Reactor Trip System (RTS) Instrumentation
2	3.3.2	Engineered Safety Feature Actuation System (ESFAS) Instrumentation
3	3.3.5	Loss of Power (LOP) Diesel Generator (DG) Start and Bus Separation Instrumentation

The following discussion provides a description of, and basis for, the proposed changes that are contained in Attachment A. The justification for the proposed changes is provided in Section 3.0.

Change No. 1

Technical Specification 3.3.1, Reactor Trip System (RTS) Instrumentation.

1) The bypass test time in the Note of the Required Actions for Condition D is increased from 4 hours to 12 hours, the Completion Time for Required Actions D.1.1 and D.2.1 is increased from 6 hours to 72 hours, and the Completion Time for Required Actions D.1.2 and D.3 is increased from 12 hours to 78 hours.

2) The bypass test time in the Note of the Required Actions for Condition E is increased from 4 hours to 12 hours, the Completion Time for Required Action E.1 is increased from 6 hours to 72 hours, and the Completion Time for Required Action E.2 is increased from 12 hours to 78 hours.

3) The bypass test time in the Note of the Required Actions for Condition K is increased from 4 hours to 12 hours, the Completion Time for Required Action K.1 is increased from 6 hours to 72 hours, and the Completion Time for Required Action K.2 is increased from 12 hours to 78 hours.

4) The bypass test time in the Note of the Required Actions for Condition L is increased from 4 hours to 12 hours, the Completion Time for Required Action L.1 is increased from 6 hours to 72 hours, and the Completion Time for Required Action L.2 is increased from 10 hours to 76 hours.

5) The Completion Time for Required Action M.1 is increased from 6 hours to 24 hours, and the Completion Time for Required Action M.2 is increased from 12 hours to 30 hours.

6) The bypass test time in Note 1 of the Required Actions for Condition N is increased from 2 hours to 4 hours, Note 2 is deleted, the Completion Time for Required Action N.1 is increased from 1 hour to 24 hours, and the Completion Time for Required Action N.2 is increased from 7 hours to 30 hours.

7) The bypass test time in the Note of the Required Actions for Condition R is increased from 4 hours to 12 hours, and the Completion Time for Required Action R.1 is increased from 6 hours to 72 hours.

8) The Frequency of the TRIP ACTUATION DEVICE OPERATIONAL TEST (TADOT) in SURVEILLANCE REQUIREMENT (SR) 3.3.1.4 is increased from 31 days on a STAGGERED TEST BASIS to 62 days on a STAGGERED TEST BASIS.

9) The Frequency of the ACTUATION LOGIC TEST in SR 3.3.1.5 is increased from 31 days on a STAGGERED TEST BASIS to 92 days on a STAGGERED TEST BASIS.

10) The Frequency of the CHANNEL OPERATIONAL TEST (COT) in SR 3.3.1.6 is increased from 92 days to 184 days.

11) The Frequency of the Note for SR 3.3.1.7 is increased from 92 days to 184 days, and the Frequency of SR 3.3.1.7 is increased from 92 days to 184 days.

12) The Frequency of the TADOT in SR 3.3.1.8 is increased from 92 days to 184 days.

Change No. 2

Technical Specification 3.3.2, Engineered Safety Feature Actuation System (ESFAS) Instrumentation.

1) The Completion Time for Required Action C.1 is increased from 6 hours to 24 hours, the Completion Time for Required Action C.2.1 is increased from 12 hours to 30 hours, and the Completion Time for Required Action C.2.2 is increased from 42 hours to 60 hours.

2) The bypass test time in the Note of the Required Actions for Condition D is increased from 4 hours to 12 hours, the Completion Time for Required Action D.1 is increased from 6 hours to 72 hours, the Completion Time for Required Action D.2.1 is increased from 12 hours to 78 hours, and the Completion Time for Required Action D.2.2 is increased from 18 hours to 84 hours.

3) The bypass test time in the Note of the Required Actions for Condition E is increased from 4 hours to 12 hours, the Completion Time for Required Action E.1 is increased from 6 hours to 72 hours, the Completion Time for Required Action E.2.1 is increased from 12 hours to 78 hours, and the Completion Time for Required Action E.2.2 is increased from 18 hours to 84 hours.

4) The Completion Time for Required Action G.1 is increased from 6 hours to 24 hours, the Completion Time for Required Action G.2.1 is increased from 12 hours to 30 hours, and the Completion Time for Required Action G.2.2 is increased from 18 hours to 36 hours.

5) The bypass test time in the Note of the Required Actions for Condition H is increased from 4 hours to 12 hours, the Completion Time for Required Action H.1 is increased from 6 hours to 72 hours, and the Completion Time for Required Action H.2 is increased from 12 hours to 78 hours.

6) The bypass test time in the Note of the Required Actions for Condition J is increased from 4 hours to 12 hours, the Completion Time for Required Action J.1 is increased from 6 hours to 72 hours, the Completion Time for Required Action J.2.1 is increased from 12 hours to 78 hours, and the Completion Time for Required Action J.2.2 is increased from 42 hours to 108 hours.

7) The Frequency of the ACTUATION LOGIC TEST in SR 3.3.2.2 is increased from 31 days on a STAGGERED TEST BASIS to 92 days on a STAGGERED TEST BASIS.

8) The Frequency of the MASTER RELAY TEST in SR 3.3.2.3 is increased from 31 days on a STAGGERED TEST BASIS to 92 days on a STAGGERED TEST BASIS.

9) The Frequency of the COT in SR 3.3.2.4 is increased from 92 days to 184 days.

10) The Frequency of the TADOT in SR 3.3.2.5 is increased from 92 days to 184 days.

<u>Change No. 3</u>

Technical Specification 3.3.5, Loss of Power (LOP) Diesel Generator (DG) Start and Bus Separation Instrumentation.

1) The bypass test time in the Note of the Required Actions for Condition B is increased from 4 hours to 12 hours and the Completion Time for Required Action B.1 is increased from 6 hours to 72 hours.

2) The Frequency of the TADOT in SR 3.3.5.1 is increased from 92 days to 184 days.

Basis for Change Nos. 1, 2, and 3

The proposed changes to the bypass test times, Completion Times, and Surveillance Frequencies described in Changes Nos. 1, 2, and 3 above are either:

- Generically approved by the NRC in WCAP-14333-P-A, Revision 1 (Reference 1), WCAP-15376-P-A, Revision 1 (Reference 2), TSTF-411, Revision 1, the TSTF associated with WCAP-15376-P-A, Revision 1 (Reference 3), and TSTF-418, Revision 2, the TSTF associated with WCAP-14333-P-A, Revision 1 (Reference 4). The applicability of these generically approved changes to BVPS is provided in Section 3.0, or

- A justification for the plant specific instrument Functions not addressed in the WCAP-10271-P-A series of topical reports, WCAP-14333-P-A, Revision 1 or WCAP-15376-P-A, Revision 1 is provided in Section 3.0.

The Technical Specification Bases associated with Technical Specification 3.3.1, Technical Specification 3.3.2, and Technical Specification 3.3.5 are also revised to reflect the changes discussed above.

3.0 TECHNICAL EVALUATION

A survey was provided to all WOG (now called the PWROG) 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. The Technical Specification changes evaluated in WCAP-14333 and WCAP-15376 were identified from the survey information. The probabilistic risk analysis, benefits of the program and conclusions, and the relationship of the Technical Specification changes to the analyses are discussed in WCAP-14333 and WCAP-15376.

In order to model the Completion Times in the fault trees used to determine the impact of the changes on signal unavailabilities, several parameters were specified for component test and maintenance unavailabilities. These are the test frequencies and durations discussed in Section 5.1 of WCAP-14333, the

maintenance frequencies and durations discussed in Section 5.2 of WCAP-14333, and the test and maintenance activities discussed in Section 7.2 of WCAP-15376.

3.1 Probabilistic Risk Analysis Evaluation

The changes considered in these analyses 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 bypass test time, Completion Time, and Surveillance Frequency changes. The second tier addresses avoidance of risk-significant plant configurations. The third tier addresses risk-informed plant configuration control and management.

3.1.1 Tier 1, PRA Capability and Insights

WCAP-14333

WCAP-14333 originally provided only the impact of the requested changes on core damage frequency (ΔCDF) for two-out-of-four (2/4) and two-out-of-three (2/3) actuation logic. In response to an NRC request for additional information (RAI) letter, RAI Questions 11 and 13 in WOG letter OG-96-110 (Reference 8), the WOG provided the impact of the requested changes on incremental conditional core damage probability (ICCDP) for various components in maintenance for the proposed changes, and the change in large early release frequency (ΔLERF) for 2/4 and 2/3 actuation logic for the proposed changes. Additionally, in response to an NRC RAI on SNC's LAR to implement these changes for Vogtle Units 1 and 2 (Reference 6), incremental conditional large early release probabilities (ICLERP) values for various components in maintenance were provided.

The impact of the proposed changes on CDF and LERF are provided in TSTF-418, Revision 2, Table 1.3 (which is the same information as that contained in Table 8.4 of WCAP-14333) and Table 1.4 (which is the same information as that contained in the response to RAI Question 13 in OG-96-110 (Reference 8)), respectively. This information is summarized in Table 4 of this LAR. The CDF and LERF values are provided and referenced to the pre-TOP and TOP conditions. The

results of a sensitivity analysis are also provided in Table 8.4 of WCAP-14333 that credits a 0.5/year reduction in reactor trip frequency due to fewer analog channel operational tests (COTs) (trip reduction originally postulated for the WCAP-10271 analog channel operational test Frequency increase from monthly to quarterly). The ΔCDF and ΔLERF values are also provided in Table 4 of this LAR for both a 2/4 and 2/3 logic. The ICCDP and ICLERP values are provided on Table 1.5 of TSTF-418, Revision 2 (the ICCDP values are from Table Q11.1 in the response to RAI Question 11 in OG-96-110 (Reference 8) and the ICLERP values in SNC's RAI response in Reference 6). The ICCDP and ICLERP values are provided only for 2/3 logic; however, the results bound the 2/4 logic.

The BVPS Unit 1 CDF for internal and external events is 1.95E-05/yr and LERF for internal and external events is 7.54E-08/yr. The BVPS Unit 2 CDF for internal and external events is 2.40E-05/yr and LERF for internal and external events is 4.09E-07/yr. These are consistent with the guidelines in Regulatory Guide 1.174 that allows small increases in CDF and LERF. Per this Regulatory Guide, for a total CDF of 1E-04/yr, changes to CDF of 1E-06/yr are acceptable and for a total LERF of 1E-05/yr, changes to LERF of 1E-07/yr are acceptable.

The calculated increase in CDF for the changes in WCAP-14333, obtained from the data in Table 8.4 of the WCAP, is 3.5E-07/yr for plants with predominately 2/4 logic requirements and 6.1E-07/yr for plants with predominately 2/3 logic. The calculated increase in LERF due to the changes in WCAP-14333, obtained from the data in Table Q13.1 in Letter OG-96-110 (Reference 8) , is 2.0E-08/yr for plants with predominately 2/4 logic requirements and 2.2E-08/yr for plants with predominately 2/3 logic. BVPS Units 1 and 2 are predominately 2/3 logic plants.

Therefore, it is concluded that implementing the changes in WCAP-14333 will have an impact on CDF of less than 1.0E-06/yr and on LERF of less than 1.0E-07/yr, which meets the guidance in Regulatory Guide 1.174.

External Events

The analysis supporting the changes in WCAP-14333 did not include external events. Seismic and fire external events are quantitatively assessed in the BVPS Units 1 and 2 PRA models. The accident sequences from the CDF quantifications for these events for each unit were reviewed to identify sequences that contain failures of engineered safety features (ESF) actuation signals. These signals are identified in the sequences as SA (SSPS Train A) and SB (SSPS Train B). The results, in terms of CDF for the fire and seismic sequences that contain probabilistic failures of the actuation signals, are provided in Table 3.

Table 3
External Event Assessment Results
Percent External Event CDF Related to Actuation Signals

Parameter	Probabilistic train failure	Unit 1	Unit 2
CDF for ESF Actuation Signal Failures	SA	1.00E-07/yr	1.43E-07/yr
	SB	1.05E-07/yr	1.48E-07/yr
Total CDF Seismic and Fire		1.56E-05/yr	1.45E-05/yr
Percent Contribution to CDF	SA	0.6%	1.0%
	SB	0.7%	1.0%

This demonstrates that actuation signal failures or unavailabilities are very small contributors to the CDF for both units for external events. Therefore, the small increases in the signal unavailabilities proposed by the changes in WCAP-14333 will have a very small impact on the external event CDF and will not impact the acceptability of the changes.

Note for external events, the BVPS PRA models do not model failure of reactor trip leading to an ATWS event. The primary contribution of ATWS events to CDF is from internal transient events, such as turbine trip and loss of main feedwater. In the PRA model, internal transient events typically have frequencies of about 1 to 2 per year. External events, such as fires and seismic, are relatively infrequent

events with initiating event frequencies significantly less than internal transient events. Furthermore, the reactor trip failure probability is about 3E-06, so the total CDF from external events with reactor trip failures is estimated to be less than 1E-07 at BVPS Unit 1 and less than 8E-08 at BVPS Unit 2. Therefore, excluding the ATWS contribution to CDF from external events is acceptable due to the very small contribution to CDF from this source. Since the impact of the proposed changes to reactor trip signal unavailability on CDF from internal events is very low, the impact from external events will also be very small and not explicitly including them will not impact the conclusions from this assessment.

WCAP-15376

The risk analysis results for WCAP-15376 are discussed in Section 8.4 of the WCAP. Comparisons are presented in Tables 8.29 (ΔCDF) and 8.32 (ΔLERF) to a base case which represents the changes previously approved in WCAP-14333. These values are summarized in Table 4. In response to an NRC request for additional information letter, RAI Questions 4 and 11 in WOG letter OG-02-002 (Reference 9), the WOG provided the impact of the requested Completion Time change (24 hour Completion Time plus 6 hours to reach MODE 3, for a total of 30 hours) on ICCDP and ICLERP for a reactor trip breaker (RTB) in preventive maintenance (PM) or in corrective maintenance (CM), with the associated logic train inoperable, for the bounding 2/3 logic. Since these incremental risk metrics are met for a 30-hour maintenance time, they will also be met for a 4-hour bypass test time.

The BVPS Unit 1 CDF for internal and external events is 1.95E-05/yr and LERF for internal and external events is 7.54E-08/yr. The BVPS Unit 2 CDF for internal and external events is 2.40E-05/yr and LERF for internal and external events is 4.09E-07/yr. These values are consistent with the guidelines in Regulatory Guide 1.174 that allows small increases in CDF and LERF. Per this Regulatory Guide, for a total CDF of 1E-04/yr, changes to CDF of 1E-06/yr are acceptable and for a total LERF of 1E-05/yr, changes to LERF of 1E-07/yr are acceptable. The calculated increase in CDF for the changes in WCAP-15376, as provided in Table 8.29 of the WCAP, is 8.0E-07/yr for plants with predominately a 2/4 logic and

8.5E-07/yr for plants with predominately a 2/3 logic. The calculated increase in LERF due to the Technical Specification changes justified in WCAP-15376, as provided in Table 8.32 of the WCAP, is 3.1E-08/yr for plants with predominately a 2/4 logic and 5.7E-08/yr for plants with predominately a 2/3 logic .

Therefore, it is concluded that implementing the Technical Specification changes justified in WCAP-15376 will have an impact on CDF of less than 1.0E-06/yr and on LERF of less than 1.0E-07/yr, which meets the guidance in Regulatory Guide 1.174.

As previously discussed, the analysis supporting the changes in WCAP-15376 did not include external events. Seismic and fire external events are quantitatively assessed in the BVPS Units 1 and 2 PRA models. Actuation signal failures or unavailabilities are very small contributors to the CDF for both units for external events (see the previous discussion of external events including Table 3 of this LAR).

Therefore, it is concluded that the small increases in the signal unavailabilities proposed by the Technical Specification changes justified in WCAP-15376 will have a very small impact on the external event CDF and will not impact the acceptability of the Technical Specification changes.

Combined Risk Metric Results

Table 4 Summary of Risk Metrics					
Risk Metric	Acceptance Criterion	Change from WCAP-10271 to WCAP-14333		Change from WCAP-14333 to WCAP-15376	
ΔCDF per year	< 1E-06	2/4 logic 3.5E-07	2/3 logic 6.1E-07	2/4 logic 8.0E-07	2/3 logic 8.5E-07
ICCDP	< 5E-07	Ranges from 4.4E-07 (logic train in maintenance) to 5.5E-10 (SG level channel in test)*		RTB in PM = 3.2E-07* RTB in CM = 3.2E-07*	
ΔLERF per year	< 1E-07	2/4 logic 2.0E-08	2/3 logic 2.2E-08	2/4 logic 3.1E-08	2/3 logic 5.7E-08
ICLERP	< 5E-08	Ranges from 3.0E-08 (logic train in maintenance) to 1.1E-11 (SG level channel in test)*		RTB in PM = 2.4E-08* RTB in CM = 2.4E-08*	

*- The ICCDP and ICLERP values are provided only for a 2/3 logic, however the results bound a 2/4 logic.

The ICCDP and ICLERP values are dependent on the particular component under test or maintenance. The acceptance criteria defined in Regulatory Guide 1.177 for these incremental risk metrics are satisfied. The ΔCDF and ΔLERF values are from the current licensing basis (WCAP-10271) to the proposed state (WCAP-15376), and do not credit the 0.5/year reduction in reactor trip frequency identified in Table 8.4 of WCAP-14333. The ΔCDF and ΔLERF acceptance criteria are satisfied for the changes included in each WCAP.

Table 8.33 for WCAP-15376 provides the cumulative impact of the Completion Time and Surveillance Frequency changes on core damage frequency from Pre-TOP to WCAP-15376. These values include credit for a trip reduction related to the reduced testing required with the extended Surveillance Frequencies. The calculated cumulative CDF impact is small.

Reactor Trip Breaker Test Configuration: WCAP-15376 Model vs. BVPS Approach

WCAP-15376, Section 8.3.2.2 states "Testing of the reactor trip breakers prohibits actuation of the breaker in test. The bypass breaker corresponding to the affected breaker is placed into service and will be actuated by the logic cabinet in the unaffected train."

Section 3.1.3 of the NRC Safety Evaluation for WCAP-15376 states "The model assumed one RTB was out-of-service with the associated bypass breaker available. The operable RTB and the in-service bypass breaker provide the reactor trip. In this arrangement both breakers are controlled by the logic cabinet associated with the operable breaker."

This means that when a Reactor Trip Breaker (RTB) Train, RTB Train A for example, is tested, this test configuration results in Actuation Logic Train B controlling the RTB in Train B, and the Reactor Trip Bypass Breaker (RTBB) in Train A, either of which will trip the reactor. This RTB test configuration was modeled in the PRA analysis supporting the RTB bypass test time change from 2 hours to 4 hours, and the RTB Surveillance Frequency change from 2 months to 4 months that were justified in WCAP-15376. This approach to RTB testing assumes that the RTB Train being tested is removed from service or in the open position during the test.

At BVPS, the RTB under test is normally open when the RTBB is in service, except when it is necessary to first have the RTB closed in order to verify that the RTB opens upon testing the RTB trip actuation devices. The time duration when the RTB is closed when the RTBB is in service is small compared to the 2 hour

bypass test time allowance and is estimated to be less than 30 minutes per surveillance test. This period is not expected to change significantly with the proposed change in RTB bypass test time allowance of 2 to 4 hours.

The impact of this alternate test configuration, with the RTB being tested in the closed position, when compared to the WCAP-15376 assumption on the acceptability of the RTB bypass test time of 4 hours and Surveillance Frequency of 4 months is evaluated below. Note that in this configuration, when the RTB being tested is closed, the associated RTBB will open upon receiving a reactor trip signal, however, for the short time the associated RTB is in test and closed, the protection train associated with the RTB being tested will not provide a reactor trip. However, it should be noted that the other protection train (that is not being tested) will provide the reactor trip function if required.

In either test configuration the RTB unavailability associated with the RTB bypass test time and Surveillance Frequency is as follows:

Prior to implementing the changes justified in WCAP-15376;

RTB bypass test time (2 hours) and Surveillance Frequency (2 months) provide an RTB yearly unavailability of 2 hours x 6 Surveillances per year = 12 hours per year.

Implementing the changes justified in WCAP-15376;

The revised RTB bypass test time (4 hours) and Surveillance Frequency (4 months) provides an RTB yearly unavailability of 4 hours x 3 Surveillances per year = 12 hours per year.

The test unavailability remains the same before and after the RTB bypass test time and Surveillance Frequency changes, for both test configurations, and therefore, the RTB bypass test time of 4 hours and Surveillance Frequency of 4 months have no impact on the WCAP-15376 risk analysis results, i.e., CDF and LERF impact. The conclusion regarding the acceptability of the changes remains the same, regardless of the RTB test configuration, i.e., the RTB unavailability does not

change with the change from the current RTB bypass test time and Surveillance Frequency to those justified in WCAP-15376-P-A Revision 1.

3.1.2 Tier 2, Avoidance of Risk-Significant Plant Configurations

Tier 2 requires an examination of the need to impose additional restrictions when operating under the proposed Completion Times. The Tier 2 restrictions are necessary in order to avoid risk-significant equipment outage configurations when the proposed Completion Times justified in this LAR are implemented. The resulting Tier 2 restrictions to be imposed for the two topical reports are very similar.

WCAP-14333

In support of Tier 2 restrictions, analyses were completed in response to an NRC RAI on WCAP-14333. RAI Question 18 asked for other risk significant systems or components for the proposed test or maintenance plant configuration. Analyses were completed in support of the response to RAI Question 18 in Reference 8, that determined the system importance for plant configurations with no ongoing test and maintenance activities (all components available), and for plant configurations with ongoing test or maintenance activities individually on the analog channels, logic cabinets, master relays, and slave relays. With test or maintenance activities in progress, it was assumed that the corresponding component or train will be unavailable. The system importance for these configurations is provided in Table Q18.1 in the response to RAI Question 18 on WCAP-14333 in OG-96-110, Reference 8. The importance values were compared between the cases with individual components unavailable and all components available. The following was concluded:

- The importance rankings of risk significant systems do not change appreciably for the configurations with an analog channel, master relay, or slave relay out of service, or unavailable, compared to the configuration with no ongoing test or maintenance activities.

- A relatively significant change in the importance rankings of risk significant systems occurs when a logic train is out of service, or unavailable, compared to the configuration with no ongoing test or maintenance activities.

RAI Question 11 on WCAP-14333 requested CDFs for the various test and maintenance configurations that the plant would enter for the subject Completion Time extensions. Conditional core damage frequencies and core damage probabilities were calculated for each of the possible test and maintenance configurations. This information is provided in Table Q11.1 in the response to RAI Question 11 on WCAP-14333 in OG-96-110, Reference 8.

Based on the information provided in Tables Q11.1 and Q18.1 in the responses to RAI Questions 11 and 18 on WCAP-14333 in OG-96-110, Reference 8, it was concluded that the only plant configuration with an appreciable impact on CDF or a significant impact on the relative importance of other systems is the configuration with one logic train unavailable.

Based on the discussions above, Tier 2 restrictions are not required when a slave relay, master relay, or analog channel is out of service. Therefore, Tier 2 restrictions are only appropriate when a logic train is removed from service.

Page 12 in Section 3.0 of the NRC Safety Evaluation (SE) for WCAP14333 states:

> "For Tiers 2 and 3, the staff finds that plant-specific information is needed because when entering the proposed AOTs, potentially risk significant configurations should be avoided. Therefore, licensees are expected to confirm that the necessary restrictions will be placed on concurrent equipment outages in order to avoid a risk significant configuration."

Entry into the Condition for an inoperable logic train is not a typical, pre-planned evolution during operation in the modes of Applicability for the logic trains, other than when necessary for surveillance testing. Since the Condition may be entered due to equipment failure, some of the following Tier 2 restrictions discussed below may not be met at the time of Condition entry. In addition, it is possible that equipment failure may occur after the logic train is removed from service for

surveillance testing or planned maintenance, such that one or more of the required Tier 2 restrictions are no longer met. In cases of equipment failure, the programs and procedures discussed below in the Tier 3 configuration risk management program section require assessment of the emergent condition and appropriate actions are then taken. Depending on the specific situation, these actions could include restoring the inoperable logic train and exiting the Technical Specification Condition, or fully implementing the Tier 2 restrictions, or performing a unit shutdown, as appropriate from a risk management perspective.

Consistent with the SE requirements for WCAP-14333, the following Tier 2 restrictions on concurrent removal of certain equipment will be implemented when a logic train is inoperable when operating under the proposed Completion Times:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable.
- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained. Note that Technical Specification 3.5.2, ECCS Operating, ensures that this restriction is met. Therefore, this restriction does not have to be implemented by a separate procedure or program.
- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays, in the available train, and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable.
- Activities on electrical systems (AC and DC power) and cooling systems (service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable. That is, one complete train of a function that supports a complete train of a function noted above must be available.

WCAP-15376

Page 15 in Section 3.3 of the NRC SE for WCAP-15376 states:

> "The licensee should provide reasonable assurance that risk significant plant equipment outage configurations will not occur when specific plant equipment is out-of-service in accordance with the proposed TS change."

The recommended Tier 2 restrictions for WCAP-15376 are provided in Section 8.5 of the WCAP. The restrictions are applicable when an RTB train is inoperable when operating under the proposed Completion Times. Entry into the Condition for an inoperable RTB train is not a typical, pre-planned evolution during operation in the modes of Applicability for the RTB train, other than when necessary for surveillance testing. Since the Condition may be entered due to equipment failure, some of the Tier 2 restrictions discussed below may not be met at the time of Condition entry. In addition, it is possible that equipment failure may occur after the RTB train is removed from service for surveillance testing or planned maintenance, such that one or more of the required Tier 2 restrictions are no longer met. In cases of equipment failure, the programs and procedures discussed below in the Tier 3 configuration risk management program section require assessment of the emergent condition and appropriate actions are then taken. Depending on the specific situation, these actions could include restoring the inoperable RTB train and exiting the Technical Specification Condition, or fully implementing the Tier 2 restrictions, or performing a unit shutdown, as appropriate from a risk management perspective.

The following Tier 2 restrictions will be implemented when an RTB train becomes inoperable when operating under the proposed Completion Times.

- The probability of failing to trip the reactor on demand will increase when a RTB is removed from service, therefore, systems designed for mitigating an ATWS event should be maintained available. RCS pressure relief (pressurizer PORVs and safety valves), auxiliary feedwater flow (for RCS heat removal), AMSAC, and turbine trip are important to ATWS mitigation. Therefore, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a RTB is inoperable.
- Due to the increased dependence on the available reactor trip train when one logic train is unavailable, activities that degrade other components of the RTS, including master relays or slave relays, and activities that cause analog channels to be unavailable, should not be scheduled when a logic train is inoperable.
- Activities on electrical systems (AC and DC power) that support the systems or functions listed in the first two bullets should not be scheduled when a RTB is inoperable.

3.1.3 Tier 3, Risk-Informed Configuration Risk Management

Tier 3 requires a proceduralized process to assess the risk associated with both planned and unplanned work activities. The objective of the third tier is to ensure that the risk impact of out-of-service equipment is evaluated prior to performing any maintenance activity. As stated in Section 2.3 of Regulatory Guide 1.177, "a viable program would be one that is able to uncover risk-significant plant equipment outage configurations in a timely manner during normal plant operation." The third-tier requirement is an extension of the second-tier requirement, but addresses the limitation of not being able to identify all possible risk-significant plant configurations in the second-tier evaluation.

Paragraph (a)(4) of the Maintenance Rule (10CFR 50.65) requires that the overall effect on safety functions be considered when removing equipment from service

for preventive maintenance or monitoring activities. In part, paragraph (a)(4) states that, "Before performing maintenance activities ... the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities...." Section 11.0 of NUMARC 93-01 provides guidance for implementing the requirements of paragraph (a)(4). NRC Regulatory Guide 1.182 endorsed the NUMARC 93-01, Section 11.0 as an acceptable method of implementing paragraph (a)(4).

The overall BVPS risk management process is defined in Procedure 1/2-ADM-2033, "Risk Management Program." The process for assessing on-line safety impact before removing a system, structure or component from service is defined in 1/2-ADM-0804, "On-Line Risk Assessment and Management.", NOP-WM-0001, "Work Management Process," and NOP-WM-2001, "Work Management Scheduling Process," define the process for developing the weekly on-line work schedule that provides the foundation for on-line risk assessment.

Programs and procedures at BVPS ensure that configuration risk is assessed using a PRA-based model and managed prior to initiating any maintenance activity consistent with the requirements of 10 CFR 50.65(a)(4). The procedures also ensure that risk is reassessed if an emergent condition results in a plant configuration that has not been previously assessed. Risk thresholds are established to ensure that the average baseline risk is maintained within an acceptable band. When administrative limits are exceeded, increasing levels of management approval are required prior to initiating the work.

3.1.4 Topical Report Safety Evaluation Conditions

The NRC's 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 insights which confirm that these insights are incorporated into the decision making process before taking equipment out of service.

The NRC's 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. This includes addressing the applicability of the master relay and safeguards driver card failure probabilities to the plant-specific application.

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 train and associated reactor trip breaker needs to be evaluated on a plant-specific basis to ensure conformance with the WCAP-15376 evaluation, 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 (OG-01-058 Reference 10) requires each plant to review their setpoint calculation methodology to determine the impact of extending the Channel Operational Test (COT) Surveillance Frequency from 92 days to 184 days.

WCAP-14333 and WCAP-15376 SE Condition 1

In order to address SE Condition 1 for both WCAPs, Westinghouse issued implementation guidelines for licensees to confirm that the WCAP analyses are applicable to their plant. A plant specific assessment was performed to confirm the applicability of the WCAP-14333 and WCAP-15376 analyses to BVPS Unit Nos. 1 and 2. The results of this assessment are provided in Enclosure 3 (proprietary) and Enclosure 4 (non-proprietary). The WCAP-15376 analysis and determination of LERF is based on a large dry containment. The containment buildings at BVPS Units 1 and 2 are considered to be large dry containments. As concluded in Enclosures 3 and 4, both WCAP analyses and results are applicable to BVPS Units 1 and 2.

Applicability of the master relay and safeguards driver card failure probabilities

It is necessary to indicate that component failure probabilities developed as part of WCAP-15376 are applicable to BVPS. For SSPS plants this includes the master relay and safeguards driver card failure probabilities. The failure probabilities for these components are based on data collected from a number of Westinghouse NSSS plants. The failure probabilities are:

Master Relays – 1.1E-05

Safeguards driver cards – 5.9E-04

A summary of the experience for these components at BVPS from 2001 to 2005 is provided in Table 5.

Table 5
Summary of Actuation and Failure Experience on the Safeguards Driver Cards and Master Relays

Parameter	Safeguards Driver Cards		Master Relays	
	Unit 1	Unit 2	Unit 1	Unit 2
Actuations	198	186	1419	1512
Failures	0	0	0	0

An analysis based on the binomial distribution was used to determine the number of expected failures for the given failure probabilities and actuations. For both components, either 0 or 1 failures would be expected. Based on the data provided in Table 5, it is concluded that the failure probabilities for these components used in the WCAP analysis are applicable to BVPS Units 1 and 2.

WCAP-14333 and WCAP-15376 SE Condition 2

The applicability of SE Condition 2 for both topical reports is addressed in the preceding Tier 2 discussion in Section 3.1.2 and Tier 3 discussion in Section 3.1.3.

WCAP-15376 SE Condition 3

The risk impact of concurrent testing of one logic train and the associated RTB is addressed by demonstrating that the WCAP-15376 analysis is applicable to BVPS. The WCAP analysis assumes that if a RTB is out of service its associated logic train is also out of service. Therefore, concurrent testing is addressed in the WCAP analysis.

WCAP-15376 SE Condition 4

A plant specific assessment was performed to confirm the applicability of the WCAP-15376 analysis, including the model assumptions for human reliability, to BVPS Unit Nos. 1 and 2. The results of this assessment are provided in Enclosures 3 and 4.

WCAP-15376 SE Condition 5

There are presently no plans to implement digital upgrades to the Reactor Protection or Engineered Safety Features Systems at BVPS Units 1 and 2.

WCAP-15376 RAI Question 18 Commitment

The response to this RAI in Reference 10 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 Channel Operational Test (COT) from 92 days to 184 days.

The BVPS RTS and ESFAS setpoint methodology includes an allowance for instrument drift. As found instrument setpoint readings are recorded during the performance of the procedures for the required surveillances. As part of these procedures, the as found readings are compared to the required setpoint tolerance and the instrument channel is adjusted, if needed, in order to maintain the channel setpoint as close to the specified setpoint as practical. If the setpoint is found outside of its allowable tolerance band, then the condition is documented and evaluated via the Corrective Action Program. The channel is required to meet the surveillance procedure requirements, which includes a review by a licensed senior reactor operator, prior to being returned to an operable status. The surveillance procedures are performed by qualified instrument and control technicians utilizing step by step written procedures and industry endorsed human performance error prevention practices.

In order to assess the potential effects of extending the surveillance frequencies from 92 days to 184 days proposed in this license amendment request, the results of the surveillance procedures were reviewed. This review utilized the data generated by completed surveillance procedures and compared the as found setpoint from the previous as left setpoint in order to determine the setpoint drift over the surveillance interval. A review of this data determined that the drift magnitudes are well within the process rack operability criteria specified by the surveillance procedures and are consistent with operability criteria for an operable channel as defined by the process rack vendor. No bias or significant adverse

trends were noted. No history of frequent process rack recalibration was noted in this review for the current surveillance frequency. Thus, it is concluded that the existing BVPS setpoint methodology supports the proposed surveillance frequency extension from 92 days to 184 days.

In addition a search of the industry operating experience database was performed in August 2007 for reactor protection and engineered safety features actuation systems at the plants that have had a license amendment previously approved which extended surveillance intervals based on WCAP-15376. These plants are; Callaway, Comanche Peak, Cook, Diablo Canyon, Vogtle and Wolf Creek (See Section 4.3 "Precedent" for more detail). The search found no problems attributed to drift at these plants since their respective license amendments approval dates.

3.1.5 Plant-Specific Evaluations for Functions not Evaluated Generically

This section provides justification for the Technical Specification changes proposed that were not included in the generic analyses approved in WCAP-10271 (as supplemented), WCAP-14333, or WCAP-15376. The justifications are provided below:

Justified in License Amendments

Insert 5 of TSTF-411 Revision 1 and Insert 4 of TSTF-418 Revision 2 state that RTS Function 11, Reactor Coolant Pump Breaker Position, was not included in the generic evaluations approved in WCAP-10271 (as supplemented), WCAP-14333, or WCAP-15376.

Insert 7 of TSTF-411 Revision 1 and Insert 14 of TSTF-418 Revision 2 state that ESFAS Function 7.b, Refueling Water Storage Tank (RWST) Level- Low (Unit 1) and Extreme Low (Unit 2), were not included in the generic analyses approved in WCAP-10271 (as supplemented), WCAP-14333, or WCAP-15376.

Insert 19 of TSTF-418, Revision 2 states that Technical Specification 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start and Bus Separation Instrumentation," was not included in the generic evaluations approved in either WCAP-10271, as supplemented, or WCAP-14333.

The following BVPS specific instrument Functions that were not evaluated generically in WCAP-10271 (as supplemented) were evaluated for BVPS in order to apply the Technical Specification relaxations justified in WCAP-10271, as supplemented, WCAP-14333, or WCAP-15376:

- Technical Specification 3.3.1, RTS Function 11; Reactor Coolant Pump Breaker Position.
- Technical Specification 3.3.2, ESFAS Function 7.b.; Refueling Water Storage Tank Level Extreme Low. It is noted that FENOC Letter L-07-017 (Reference 7) submitted a LAR that revised the nomenclature for this function (RWST Level Low -Automatic Switchover of Safety Injection to Containment Sump) by renaming the function as RWST Level Extreme Low for each unit.
- Technical Specification 3.3.5, LOP DG Start and Bus Separation Function 1; 4160V Emergency Bus DG Start – Loss of Voltage.
- Technical Specification 3.3.5, LOP DG Start and Bus Separation Function 2; 4160V Emergency Bus - Bus Separation – Loss of Voltage.
- Technical Specification 3.3.5, LOP DG Start and Bus Separation Function 3; 4160V Emergency Bus - Bus Separation – Degraded Voltage.
- Technical Specification 3.3.5, LOP DG Start and Bus Separation Function 4; 480V Emergency Bus - Bus Separation – Degraded Voltage.

Several utilities completed plant-specific evaluations to demonstrate that the changes in WCAP-10271 and its supplements were applicable to functions not generically evaluated. The analyses performed in WCAP-14333 and WCAP-15376 covered representative RTS and ESFAS functions, a subset of the comprehensive set of functions included in WCAP-10271 and its supplements.

Therefore, the changes approved in WCAP-14333 and WCAP-15376 are also applicable to those plant-specific functions with NRC-approved evaluations performed that demonstrate the applicability of the changes in WCAP-10271 and its supplements. As discussed in Section 11.0 of both WCAP-14333 and WCAP-15376, as well as in NRC-approved travelers TSTF-411, Revision 1 and TSTF-418 Revision 2, additional plant-specific evaluations are not required to implement the changes in WCAP-14333 and WCAP-15376, if they have been previously justified for the changes in WCAP-10271 and its supplements.

The applicability of the changes justified in WCAP-10271 and it supplements to current BVPS RTS Function 11, Reactor Coolant Pump Breaker Position was approved by the NRC in License Amendment 181 for Unit 1 and Amendment 61 for Unit 2 (Reference 5). These amendments extended the Completion Time for BVPS RTS Function 20 on Table 3.3-1 in Reference 5 (note the associated Action No. 11 Completion Time was changed to 6 hours on Technical Specification page 3/4 3-7 in Reference 5). Also note that the Function number and associated Action number in Reference 5 were subsequently changed when BVPS implemented the Improved Technical Specifications.

The applicability of the changes justified in WCAP-10271 and it supplements to the following list of Functions was approved by the NRC in License Amendment 267 for Unit 1 and Amendment 149 for Unit 2 (Reference 11). Note the Function numbers and associated Action numbers in Reference 11 were subsequently changed when BVPS implemented the Improved Technical Specifications.

- Technical Specification 3.3.2, ESFAS Function 7.b.; Refueling Water Storage Tank Level Extreme Low.
- Technical Specification 3.3.5, LOP DG Start and Bus Separation Function 1; 4160V Emergency Bus DG Start – Loss of Voltage.
- Technical Specification 3.3.5, LOP DG Start and Bus Separation Function 2; 4160V Emergency Bus Bus Separation – Loss of Voltage.
- Technical Specification 3.3.5, LOP DG Start and Bus Separation Function 3; 4160V Emergency Bus Bus Separation – Degraded Voltage.

- Technical Specification 3.3.5, LOP DG Start and Bus Separation Function 4; 480V Emergency Bus Bus Separation – Degraded Voltage.

In order to assess the potential effects of extending the surveillance frequencies from 92 days to 184 days proposed in this license amendment request for the above functions, the results of the surveillance procedures were reviewed. This review utilized the data generated by completed surveillance procedures and compared the as found setpoint from the previous as left setpoint in order to determine the setpoint drift over the surveillance interval. A review of this data determined that the drift magnitudes are within the relay drift allowances specified in the applicable calculations and are consistent with operability criteria for an operable channel. No bias or significant adverse trends were noted. Thus, it is concluded that the existing BVPS setpoint methodology supports the proposed surveillance frequency extension from 92 days to 184 days.

Therefore the changes justified in WCAP-14333 and WCAP-15376 are applicable to these BVPS Specific functions.

Justification for a New BVPS Specific ESFAS Function

Section 2.1 of this LAR provides a description of a pending LAR in which a new signal is being added to the protection system for BVPS Units 1 and 2 (Reference 7). This new ESFAS signal starts containment spray recirculation on containment pressure high-high coincident with RWST level low. This signal was not evaluated in WCAP-10271-P-A, Revision 1 Supplement 2 therefore; a signal unavailability analysis was completed to demonstrate that the proposed changes in that WCAP are acceptable for this new ESFAS signal. Evaluating only the signal unavailability impact is consistent with the approach used in WCAP-10271-P-A, Revision 1 Supplement 2. The WCAP-10271-P-A, Revision 1 Supplement 2 analysis evaluated the impact of the proposed changes on the unavailability of a large number of ESFAS signals and then used representative signals in the risk analysis. This approach of using representative signals is appropriate, since signal unavailabilities and the impact of the proposed changes on signal unavailability are similar for groups of signals, and the representative signals provide typical results.

Therefore, it is only necessary to assess the impact of the changes on the signal unavailability for containment spray recirculation start and demonstrate the unavailability impact is similar to the other signals previously found to be acceptable.

The containment spray recirculation start signal is part of the engineered safety feature actuation system and is composed of two trains with each containing a slave relay, master relay, and logic cabinet. Both trains receive signals from the containment pressure high-high analog channels and the RWST low level analog channels. The containment pressure high-high signal and the RWST low level signal use a 2/4 logic and a 2/3 logic, respectively.

The signal unavailability study was done consistent with the previous analyses (WCAP-10271-P-A, Revision 1, Supplement 2) with the objective to demonstrate that the impact of the proposed changes on the signal unavailability is similar to the impact on signal unavailabilities for the other signals previously evaluated and approved. The results of the analysis are provided on Table 6. For comparison, also shown on this table are the results of the signal unavailability analyses for auxiliary feedwater (AFW) pump start contained in WCAP-10271-P-A, Revision 1, Supplement 2. This signal is configured similarly to that for the recirculation containment spray start signal with regard to the logic cabinet, master relays, and slave relays. A key difference is the input analog channels. The Base Case values represent those prior to implementation of the changes justified in WCAP-10271-P-A, Revision 1, Supplement 2 and the Case 1 values represent the changes evaluated in WCAP-10271-P-A, Revision 1, Supplement 2. From this comparison it is seen that the unavailability changes for the recirculation containment spray start signal are similar to that for the AFW pump start signal, therefore, it is concluded that the proposed changes are acceptable for this new BVPS ESFAS signal as well.

Table 6 Results of Unavailability Assessment for the Containment Spray Recirculation Start Signal		
ESFAS Signal	Base Case	Case 1
Containment Spray Recirculation Start	3.55E-04	1.44E-03
AFW Pump Start - 2/4 logic	5.70E-04	2.50E-03
AFW Pump Start – 2/3 logic	6.50E-04	2.70E-03

Justification for Additional Plant Specific Surveillance Frequency Extensions

This section of plant specific evaluations addresses the extension of the TADOT Surveillance Frequency for the following RTS and ESFAS Functions:

- Technical Specification 3.3.1, RTS Function 12 – Reactor trip on Reactor Coolant Pump Under Voltage, (SR 3.3.1.8 from 92 days to 184 days),
- Technical Specification 3.3.1, RTS Function 13 - Reactor trip on Reactor Coolant Pump Under Frequency, (SR 3.3.1.8 from 92 days to 184 days), and
- Technical Specification 3.3.2, ESFAS Function 6.d –Auxiliary Feedwater pump (Turbine-Driven) start on Reactor Coolant Pump Under Voltage (SR 3.3.2.5 from 92 days to 184 days). Note that this Function uses the same under voltage relays as RTS Function 12 above.

The RTS Functions listed above were included in the evaluations performed to justify the changes in WCAP-10271, Supplement 1-P-A, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System, Supplement 1," May 1986, as identified in Tables 3.2-2 and 3.2-3 of the WCAP. The ESFAS Function listed above was included in the evaluations performed to justify the changes in WCAP-10271, Supplement 1-P-A,

"Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System, Supplement 2, Revision 1" May 1989, as identified in Table 3.1-3 of the WCAP. One of the changes justified in WCAP-10271-P-A and its supplements was the extension of the applicable Surveillance Frequency for the Functions listed above from 1 month to 3 months. The affected Surveillance is called a Trip Actuating Device Operational Test (TADOT).

WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," justified extending the bypass test times and Completion Times for the signals included in WCAP-10271-P-A and its supplements, by utilizing a "representative signal approach," in the unavailability analysis that determined the impact of the proposed changes on the signal unavailability. The results of the evaluation of the "representative signals," were representative of all of the signals that were evaluated in WCAP-10271-P-A and its supplements. The bypass test time and Completion Time changes that were justified in WCAP-14333-P-A, Revision 1 are identified in Tables 5.1 and 5.2 of the WCAP. Note that the maintenance time and interval, and test time and interval values listed in these tables for the "Analog Channels" are applicable to both the Channel Operational Test (COT) and the TADOT. The analysis did not distinguish between the two types of tests, since they impact comparable components in the same manner. This is stated in Section 11 of WCAP-14333-P-A, Revision 1 as: "These recommendations are applicable to all the signals evaluated in WOG TOP for both solid state and relay protection systems" (i.e., all signals evaluated in WCAP-10271-P-A and its supplements).

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," justified extending the Surveillance Frequencies and reactor trip breaker bypass test time and Completion Times identified in Tables 4.1 and 4.2 of the WCAP. WCAP-15376-P-A, Revision 1 also utilized the "representative signal approach" that was utilized in WCAP-14333-P-A, Revision 1. One of the changes justified in WCAP-15376-P-A, Revision 1 was the extension of the Frequency of

the COT from 92 days to 184 days. This change is identified as "Analog Channels" in the "Component Column" of Tables 4.1 and 4.2 of WCAP-15376-P-A, Revision 1. The value of 6 months listed in the "Surveillance Test Intervals," column associated with the "Analog Channel" in Tables 4.1 and 4.2 of WCAP-15376-P-A, Revision 1 is applicable to both the COT and the TADOT. There was no intent to exclude the TADOT from the test interval extension to 6 months. Since the applicable TADOT frequencies were justified to be extended from 1 month to 3 months in WCAP-10271-P-A and its supplements, and the changes justified in WCAP-14333-P-A, Revision 1 and WCAP-15376-P-A, Revision 1 are applicable to all of the signals included in WCAP-10271-P-A and its supplements, the extension of the above listed TADOT Frequencies from 92 days to 184 days was also justified by WCAP-15376-P-A. This is stated in Section 11 of WCAP-15376-P-A, Revision 1 as "These recommendations are applicable to all the signals evaluated in WOG TOP for both solid state and relay protection systems ..." (i.e., all signals evaluated in WCAP-10271-P-A and its supplements).

In order to assess the potential effects of extending the surveillance frequencies from 92 days to 184 days proposed in this license amendment request for the above functions, the results of the surveillance procedures were reviewed. This review utilized the data generated by completed surveillance procedures and compared the as found setpoint from the previous as left setpoint in order to determine the setpoint drift over the surveillance interval. A review of this data determined that the drift magnitudes are within the relay drift allowances specified in the applicable calculations and are consistent with operability criteria for an operable channel. No bias or significant adverse trends were noted. Thus, it is concluded that the existing BVPS setpoint methodology supports the proposed surveillance frequency extension from 92 days to 184 days.

Therefore, the extension of the TADOT Frequencies from 92 days to 184 days justified in WCAP-14333 and WCAP-15376 are applicable to the RTS and ESFAS Functions listed above.

3.1.6 Deviations from approved TSTFs

Design Differences

BVPS Units 1 and 2 do not have installed bypass test capability for analog channels, with the exception of Containment Pressure High-High and Refueling Water Storage Tank Level Extreme Low. The bypass test Notes for plants with that design are not used in the BVPS Technical Specifications.

Superseding Changes

The changes in TSTF-418 Revision 2 regarding the Technical Specification 3.3.1 Condition for RTBs are superseded by the changes in TSTF-411 Revision 1. Option 3 of Insert 6 in TSTF-411 Revision 1 is utilized for the Note in the Required Actions for Condition N.

New BVPS Specific ESFAS Function

On February 9, 2007 (Reference 7) FENOC submitted LARs 334 and 205 that contain Technical Specification changes that are related to the Technical Specification changes proposed in this submittal. The February 9, 2007 submittal proposed a change to ESFAS Technical Specification 3.3.2 Function 2 on Table 3.3.2-1. The proposed change adds a new ESFAS Function (2.b) to Table 3.3.2-1. See Section 2.1, Pending License Amendment Requests, of this LAR for more information. The changes to the bypass test times, Completion Times and Surveillance Frequencies proposed in this submittal for the new BVPS specific ESFAS Function introduced by the February 9, 2007 LAR were not included in TSTF-411 or TSTF-418.

Additional Surveillance Frequency Extensions

The proposed changes to the TADOT Surveillance Frequencies for the following RTS and ESFAS Functions were not included in TSTF-411 or TSTF-418:

- Technical Specification 3.3.1, RTS Function 12 – Reactor trip on Reactor Coolant Pump Under Voltage (SR 3.3.1.8 from 92 days to 184 days),

- Technical Specification 3.3.1, RTS Function 13 - Reactor trip on Reactor Coolant Pump Under Frequency, (SR 3.3.1.8 from 92 days to 184 days), and
- Technical Specification 3.3.2, ESFAS Function 6.d –Auxiliary Feedwater pump (turbine-Driven) start on Reactor Coolant Pump Under Voltage (SR 3.3.2.5 from 92 days to 184 days).

3.1.7 PRA Quality

3.1.7.1 BVPS PRA Peer Review

The PRA technical acceptability of the models used in the development of this submittal has been demonstrated by a peer review process. The peer review was conducted in July 2002, by the Westinghouse Owner's Group, with the final documentation of the review issued in December 2002. After the peer review, the preliminary Category A and B facts and observations (F&Os) that potentially impacted the models were entered into the BVPS Corrective Action Program, dispositioned, and incorporated into updated PRA models. Although the facts and observations were written for the BVPS Unit 2 model, the resolution was applied to the BVPS Unit 1 model as well, as applicable. Those models have since undergone another revision, but the incorporated resolution of Category A and B facts and observations were maintained in the revision. Details of the BVPS Peer Review Category A and B F&Os have been provided to the NRC in FENOC letters L-03-160 (Reference 12) and L-04-141 (Reference 13).

3.1.7.2 Recent NRC Review of BVPS PRA Models

As part of the recent review of the BVPS Units 1 and 2 Extended Power Uprate (EPU) License Amendment Request, the NRC staff performed extensive reviews of the BVPS Unit 1 and 2 PRA models. The results of the NRC staff review was documented in Section 2.13 of the NRC Safety Evaluation Report for the Extended Power Uprate License Amendments for BVPS Units 1 and 2 (Reference 14). The review concluded that "the NRC staff finds that the PRA used in support of the EPU is of sufficient quality, scope, and level of detail to analyze the risks stemming from the EPU, consistent with the guidance in RG 1.174 (Section 2.2.3),

SRP Chapter 19 (Sections III.2.2.2, III. 2.2.3, III.2.2.4 and Appendix A) and SRP Chapter 19.1, and is, therefore, acceptable."

3.1.7.3 Cumulative Risk Considering Previous Risk-Informed Amendments

The current BVPS PRA models have incorporated the extended power uprate modifications and all risk-informed changes that were implemented prior to April 20, 2006 and November 13, 2006 for Units 1 and 2, respectively. At this time, there are no outstanding risk-informed changes that impact the PRA models or have been approved by the NRC and implemented at BVPS, which need to be incorporated into the PRA models. The cumulative impact of all of these previously accepted risk-informed changes, which impacted the PRA models, is included in the CDF and LERF of the current PRA models for BVPS Units 1 and 2. These PRA models were used in the assessments performed to justify the changes proposed in this license amendment request.

3.1.8 Monitoring Requirements Associated with the Implementation

Regulatory Guide (RG) 1.174, Section 2.3 and RG 1.177, Section 3, as part of the key principles in implementing risk-informed decision making, establishes the need for an implementation and monitoring program to ensure that extensions to TS AOT or surveillance test intervals do not degrade operational safety over time and that no adverse degradation occurs due to changes in the licensing basis due to unanticipated degradation or common cause mechanisms. An implementation and monitoring program is intended to ensure that the impact of the proposed TS change continues to reflect the reliability and availability of structures, systems and components impacted by the change. The current BVPS Maintenance Rule Program for the Reactor Protection System at both units includes condition monitoring requirements. In order to address the RG monitoring program requirements discussed above with respect to the proposed change, FENOC will review applicable BVPS programs and revise them as necessary to ensure that the intent of the RTS and ESFAS equipment unavailability and component failure modeling assumptions in WCAP-14333 and WCAP-15376 are met at BVPS.

4.0 REGULATORY EVALUATION

In this License Amendment Request (LAR) the Beaver Valley Power Station (BVPS) Units 1 and 2 Technical Specifications are being revised to implement the bypass test time, Completion Time, and Surveillance Frequency changes that were approved by the NRC in WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998; 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; TSTF-411, Revision 1, "Surveillance Test Interval Extensions for Components of the Reactor Protection System (WCAP-15376)."; and TSTF-418, Revision 2, "RPS and ESFAS Test Times and Completion Times (WCAP-14333)."

4.1 Significant Hazards Consideration

FirstEnergy Nuclear Operating Company (FENOC) has evaluated whether or not a significant hazards consideration is involved with the proposed amendments by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. Do the proposed changes involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The overall protection system performance will remain within the bounds of the previously performed accident analyses since no hardware changes are proposed. The same reactor trip system (RTS), engineered safety feature actuation system (ESFAS), and loss of power (LOP) diesel generator start and bus separation instrumentation will continue to be used. The protection systems will continue to function in a manner consistent with the plant design basis. These changes to the Technical Specifications do not result in a condition where the design, material, and construction standards that were

applicable prior to the change are altered.

The proposed changes will not modify any system interface. The proposed changes will not affect the probability of any event initiators. There will be no degradation in the performance of or an increase in the number of challenges imposed on safety-related equipment assumed to function during an accident situation. There will be no change to normal plant operating parameters or accident mitigation performance. The proposed changes will not alter any assumptions or change any mitigation actions in the radiological consequence evaluations in the Updated Final Safety Analysis Report (UFSAR).

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 to the Completion Times, bypass test times, and Surveillance Frequencies reduce the potential for inadvertent reactor trips and spurious engineered safety feature (ESF) actuations, and therefore do not increase the probability of any accident previously evaluated. The proposed changes do not change the response of the plant to any accidents and have an insignificant impact on the reliability of the RTS, ESFAS and LOP diesel generator start and bus separation signals. The RTS, ESFAS and LOP diesel generator start and bus separation instrumentation 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 the increase in core damage frequency (CDF) is less than 1.0E-06 per year and the increase in large early release frequency (LERF) is less than 1.0E-07 per year. In addition, for the Completion Time changes, 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, ESFAS and LOP diesel generator start and bus separation instrumentation will continue to perform their functions with high reliability as originally assumed, and the risk impact as measured by the ΔCDF, ΔLERF, ICCDP, and ICLERP risk metrics 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. The proposed changes are consistent with safety analysis assumptions and resultant consequences.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Do the proposed changes create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

There are no hardware changes nor are there any changes in the method by which any safety-related plant system performs its safety function. The proposed changes will not affect the normal method of plant operation. No performance requirements will be affected or eliminated. The proposed changes will not result in physical alteration to any plant system nor will there be any change in the method by which any safety-related plant system performs its safety function. There will be no setpoint changes or changes to accident analysis assumptions.

No new accident scenarios, transient precursors, failure mechanisms, or limiting single failures are introduced as a result of these changes. There will be no adverse effect or challenges imposed on any safety-related system as a result of these changes.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any previously evaluated.

3. Do the proposed changes involve a significant reduction in a margin of safety?

Response: No.

The proposed changes do not affect the acceptance criteria for any analyzed event nor is there a change to any Safety Analysis Limit (SAL). There will be no effect on the manner in which safety limits, limiting safety system settings, or limiting conditions for operation are determined nor will there be any effect on those plant systems necessary to assure the accomplishment of protection functions.

The redundancy of RTS and ESFAS trains and the LOP diesel generator start and bus separation instrumentation is maintained, and diversity with regard to the signals that provide reactor trip and ESF

actuation is also maintained. All signals credited as primary or secondary, and all operator actions credited in the accident analyses will remain the same. The proposed changes will not result in plant operation in a configuration outside the 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 times, 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 should 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 should 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) The time provided by the proposed increase in Completion Times and bypass test times should reduce the potential for human errors by the personnel performing Required Actions, corrective maintenance, and Surveillance Testing.

d) The Completion Time extensions for the reactor trip breakers should 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 Completion Times, and provide consistency with the Completion Times for the logic trains.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the above, FENOC concludes that the proposed amendments present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

4.2 Applicable Regulatory Requirements/Criteria

A review of 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants" and the Regulatory Guides, was conducted to assess the potential impact associated with the proposed changes. The General Design Criteria (GDC) and the Regulatory Guides (RG) were evaluated as follows:

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 the capability to perform their safety functions.

GDC 4 requires that structures, systems, and components important to safety be designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with the 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, 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.

10 CFR 50.55a(h)(2) requires that the protection systems are consistent with their licensing basis or IEEE 603-1991 for plants whose Construction Permit was issued before January 1, 1971, or that the protection systems meet IEEE 279-1971 or IEEE 603-1991 for plants whose Construction Permit was issued after January 1, 1971, but before May 13, 1999. Since the Construction Permit for Unit 1 was issued on June 20, 1970, the Unit 1 protection systems are consistent with the licensing basis for Unit 1 or IEEE 603-1991. Since the Construction Permit for Unit 2 was issued on May 3, 1974, the Unit 2 protection systems meet IEEE 279-1971 or IEEE 603-1991. Section 4.2 of IEEE 279-1971 discusses the general functional requirement for protection systems to assure they satisfy the single failure criterion.

There will be no changes to the RTS, ESFAS or LOP instrumentation design such that compliance with the regulatory requirements and guidance documents discussed above would come into question. This review confirms that the plant will continue to comply with these applicable regulatory requirements.

Assessment

No change to either unit's Updated Final Safety Analysis Report (UFSAR) description of conformance to the GDCs or the listed Regulatory Guides is required as a result of the changes proposed in this LAR.

4.3 Precedent

The following plants have made submittals proposing changes similar to those being proposed in this LAR.

- Donald C. Cook, submitted on August 30, 2002, approved on May 23, 2003 as Amendments 277 (Unit 1) and 260 (Unit 2).
- Wolf Creek, submitted on December 15, 2003, approved on January 31, 2005 as Amendment 156.

- Callaway, submitted on December 17, 2003, approved on January 31, 2005 as Amendment 165.
- Comanche Peak, submitted on January 21, 2004, approved on January 31, 2005 as Amendments 114 for both units.
- Diablo Canyon, submitted on February 13, 2004, approved on January 31, 2005 as Amendments 179 (Unit 1) and 181 (Unit 2).
- Vogtle, submitted on January 27, 2005, approved on September 1, 2006 as Amendments 145 (Unit 1) and 125 (Unit 2).
- Virgil C. Summer, submitted on November 15, 2005, approved on October 24, 2006 as Amendment 177.

The Wolf Creek, Callaway, Comanche Peak and Diablo Canyon submittals proposed the changes justified by WCAP-14333 and WCAP-15376.

The Donald C. Cook and Vogtle submittals proposed the changes justified by WCAP-15376.

The Virgil C. Summer submittal proposed the changes justified by WCAP-14333.

4.4 Conclusions

In conclusion, 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) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

5.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendments would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendments do not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendments meet the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendments.

6.0 REFERENCES

1. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.
2. 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.
3. Technical Specification Task Force Traveler, TSTF-411, Revision 1, "Surveillance Test Interval Extensions for Components of the Reactor Protection System (WCAP-15376)."
4. Technical Specification Task Force Traveler, TSTF-418, Revision 2, "RPS and ESFAS Test Times and Completion Times (WCAP-14333)."
5. Issuance of Amendments Nos. 181 and 61 to Facility Operating License Nos. DPR-66 and NPF-73, Beaver Valley Power Station, Unit Nos. 1 and 2 in Response to Change Request Nos. 173/35 (TAC Nos. M88613 and M88614), dated August 8, 1995.

6. Southern Nuclear Operating Company letter LCV-1364, "Vogtle Electric Generating Plant Request to Revise Technical Specifications Reactor Trip System and Engineered Safety Features Actuation System Completion Times and Bypass Test Times," dated October 13, 1999 and LCV-1364-A, "Vogtle Electric Generating Plant Request to Revise Technical Specifications Reactor Trip System and Engineered Safety Features Actuation System Completion Times and Bypass Test Times Response to Request for Additional Information," dated June 1, 2000, Docket Numbers 50-424 and 50-425.

7. FENOC Letter L-07-017, Beaver Valley Power Station, Unit Nos.1 and 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, License Amendment Request Nos. 334 and 205, dated February 9, 2007.

8. Westinghouse Owners Group letter, OG-96-110, "Transmittal of Response to Request for Additional Information (RAI) Regarding WCAP-14333-P Entitled "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," dated December 20, 1996.

9. Westinghouse Owners Group letter OG-02-002, "Transmittal of Response to Request for Additional Information (RAI) Numbers 4 and 11 Regarding WCAP-15376-P, Revision 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.

10. Westinghouse Owners Group letter OG-01-058, "Transmittal of Response to Request for Additional Information (RAI) Regarding WCAP-15376-P, Revision 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.

11. Amendment Nos. 267 and 149, Beaver Valley Power Station, Unit Nos. 1 and 2 (BVPS-1 and 2) – Issuance of Amendment Re: Reactor Trip System (RTS) and Engineered Safety Features Actuation System (ESFAS) Instrumentation Surveillance Extension (TAC Nos. MC3404 and MC3405), dated September 19, 2005.
12. FENOC Letter L-03-160, Beaver Valley Power Station, Unit No. 2, BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests No. 180, dated October 24, 2003.
13. FENOC Letter L-04-141, Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66 and BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests Nos. 306 and 176, Emergency Diesel Generator Allowed Outage Time Extension, dated October 29, 2004.
14. Amendment Nos. 275 and 156, Beaver Valley Power Station, Unit Nos. 1 and 2 (BVPS-1 and 2) – Issuance of Amendment Regarding the 8-Percent Extended Power Uprate (TAC Nos. MC4645 and MC4646), dated July 19, 2006.

Enclosure 1, Attachment A

Beaver Valley Power Station
Proposed Technical Specification Changes

License Amendment Request 07-005

The following is a list of the affected pages:

3.3.1 – 1 *
3.3.1 – 2
3.3.1 – 3
3.3.1 – 4
3.3.1 – 5
3.3.1 – 6
3.3.1 – 7
3.3.1 – 8
3.3.1 – 9
3.3.1 – 10
3.3.1 – 11 *
3.3.2 – 1
3.3.2 – 2
3.3.2 – 3
3.3.2 – 4
3.3.2 – 5
3.3.2 – 6 *
3.3.2 – 7 *
3.3.5 – 1
3.3.5 – 2

* No Change. Page included for context only.

3.3 INSTRUMENTATION

3.3.1 Reactor Trip System (RTS) Instrumentation

LCO 3.3.1 The RTS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1.

ACTIONS

- NOTE -
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s) or train(s).	Immediately
B. One Manual Reactor Trip channel inoperable.	B.1 Restore channel to OPERABLE status.	48 hours
	OR	
	B.2 Be in MODE 3.	54 hours
C. One channel or train inoperable.	C.1 Restore channel or train to OPERABLE status.	48 hours
	OR	
	C.2.1 Initiate action to fully insert all rods.	48 hours
	AND	
	C.2.2 Place the Rod Control System in a condition incapable of rod withdrawal.	49 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One Power Range Neutron Flux - High channel inoperable.	---------- **- NOTE -** The inoperable channel may be bypassed for up to ~~4~~12 hours for surveillance testing and setpoint adjustment of other channels. ----------	
	D.1.1 Place channel in trip.	~~6~~72 hours
	AND	
	D.1.2 Reduce THERMAL POWER to ≤ 75% RTP.	~~12~~78 hours
	OR	
	D.2.1 Place channel in trip.	~~6~~72 hours
	AND	
	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
	OR	
	D.3 Be in MODE 3.	~~12~~78 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One channel inoperable.	---------- **- NOTE -** The inoperable channel may be bypassed for up to ~~4~~12 hours for surveillance testing of other channels. ----------	
	E.1 Place channel in trip.	~~6~~72 hours
	OR	
	E.2 Be in MODE 3.	~~12~~78 hours
F. One Intermediate Range Neutron Flux channel inoperable.	F.1 Reduce THERMAL POWER to < P-6.	24 hours
	OR	
	F.2 Increase THERMAL POWER to > P -10.	24 hours
G. Two Intermediate Range Neutron Flux channels inoperable.	G.1 ---------- **- NOTE -** Limited plant cooldown or boron dilution is allowed provided the change is accounted for in the calculated SDM. ----------	
	Suspend operations involving positive reactivity additions.	Immediately
	AND	
	G.2 Reduce THERMAL POWER to < P-6.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. One Source Range Neutron Flux channel inoperable.	---------- **- NOTE -** Limited plant cooldown or boron dilution is allowed provided the change is accounted for in the calculated SDM. ----------	
	H.1 Suspend operations involving positive reactivity additions.	Immediately
I. Two Source Range Neutron Flux channels inoperable.	I.1 Open reactor trip breakers (RTBs).	Immediately
J. One Source Range Neutron Flux channel inoperable.	J.1 Restore channel to OPERABLE status.	48 hours
	OR	
	J.2.1 Initiate action to fully insert all rods.	48 hours
	AND	
	J.2.2 Place the Rod Control System in a condition incapable of rod withdrawal.	49 hours
K. One channel inoperable.	---------- **- NOTE -** The inoperable channel may be bypassed for up to ~~4~~12 hours for surveillance testing of other channels. ----------	
	K .1 Place channel in trip.	~~6~~72 hours
	OR	
	K.2 Reduce THERMAL POWER to < P-7.	~~12~~78 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. One Turbine Trip channel inoperable.	---------- **- NOTE -** The inoperable channel may be bypassed for up to ~~4~~12 hours for surveillance testing of other channels. ----------	
	L.1 Place channel in trip.	~~6~~72 hours
	OR	
	L.2 Reduce THERMAL POWER to < P-9.	~~10~~76 hours
M. One train inoperable.	---------- **- NOTE -** One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ----------	
	M.1 Restore train to OPERABLE status.	~~6~~24 hours
	OR	
	M.2 Be in MODE 3.	~~12~~30 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
N. One RTB train inoperable.	---------- **- NOTES -** ~~1.~~ One train may be bypassed for up to ~~24~~ 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.~~ ----------	
	N.1 Restore train to OPERABLE status.	~~1~~24 hours
	OR	
	N.2 Be in MODE 3.	~~7~~30 hours
O. One or more channels inoperable.	O.1 Verify interlock is in required state for existing unit conditions.	1 hour
	OR	
	O.2 Be in MODE 3.	7 hours
P. One or more channels inoperable.	P.1 Verify interlock is in required state for existing unit conditions.	1 hour
	OR	
	P.2 Be in MODE 2.	7 hours
Q. One trip mechanism inoperable for one RTB.	Q.1 Restore inoperable trip mechanism to OPERABLE status.	48 hours
	OR	
	Q.2 Be in MODE 3.	54 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
R. One channel inoperable.	--- **- NOTE -** The inoperable channel may be bypassed for up to ~~4~~12 hours for surveillance testing of other channels. --- R.1 Place channel in trip.	~~6~~72 hours
S. Required Action and associated Completion Time of Condition R not met. OR Two or more channels inoperable.	S.1.1 Initiate action to fully insert all rods. AND S.1.2 Initiate action to place the Rod Control System in a condition incapable of rod withdrawal. OR S.2 Initiate action to borate the RCS to > the all rods out (ARO) critical boron concentration.	Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

- NOTE -
Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.2	**- NOTE -** Not required to be performed until 24 hours after THERMAL POWER is ≥ 15% RTP. Compare results of calorimetric heat balance calculation to power range channel output. Adjust power range channel output if calorimetric heat balance calculations results exceed power range channel output by more than +2% RTP.	24 hours
SR 3.3.1.3	**- NOTE -** Not required to be performed until 7 days after THERMAL POWER is ≥ 50% RTP. Compare results of the incore detector measurements to Nuclear Instrumentation System (NIS) AFD. Adjust NIS channel if absolute difference is ≥ 3%.	31 effective full power days (EFPD)
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.	~~31~~62 days on a STAGGERED TEST BASIS
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	~~31~~92 days on a STAGGERED TEST BASIS

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.6	--- **- NOTE -** Not required to be performed for source range instrumentation until 12 hours after power has been reduced below P-6. --- Perform COT.	~~92~~184 days
SR 3.3.1.7	--- **- NOTE -** This Surveillance shall include verification that interlocks P-6 and P-10 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 AND Twelve hours after reducing power below P-10 for power and intermediate range instrumentation AND Every ~~92~~184 days thereafter

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.8	---------- **- NOTE -** Verification of setpoint is not required. ---------- Perform TADOT.	~~92~~184 days
SR 3.3.1.9	---------- **- NOTE -** Not required to be performed until 7 days after THERMAL POWER is ≥ 50% RTP. ---------- Calibrate excore channels to agree with incore detector measurements.	Once per fuel cycle
SR 3.3.1.10	---------- **- NOTES -** 1. This Surveillance shall include verification that the time constants are adjusted to the prescribed values. 2. Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION.	18 months
SR 3.3.1.11	Perform COT.	18 months
SR 3.3.1.12	---------- **- NOTE -** Verification of setpoint is not required. ---------- Perform TADOT.	18 months

No change. Page included for context only.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.13	--- **- NOTE -** Verification of setpoint is not required. --- Perform TADOT.	Prior to exceeding the P-9 interlock whenever the unit has been in MODE 3, if not performed within the previous 31 days
SR 3.3.1.14	--- **- NOTE -** Neutron detectors are excluded from response time testing. --- Verify RTS RESPONSE TIME is within limits.	18 months on a STAGGERED TEST BASIS

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS

- NOTE -
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
B. One channel or train inoperable.	B.1 Restore channel or train to OPERABLE status. OR B.2.1 Be in MODE 3. AND B.2.2 Be in MODE 5.	48 hours 54 hours 84 hours
C. One train inoperable.	--- **- NOTE -** One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. --- C.1 Restore train to OPERABLE status. OR	 ~~6~~24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	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.	---------- **- NOTE -** The inoperable channel may be bypassed for up to 4~~1~~12 hours for surveillance testing of other channels. ----------	
	D.1 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
E. One Containment Pressure channel inoperable.	---------- **- NOTE -** One ~~additional~~ channel may be bypassed for up to 4~~1~~12 hours for surveillance testing. ----------	
	E.1 Place channel in bypass.	~~6~~72 hours
	OR	
	E.2.1 Be in MODE 3.	~~12~~78 hours
	AND	
	E.2.2 Be in MODE 4.	~~18~~84 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
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 train inoperable.	---------- **- NOTE -** One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ----------	
	G.1 Restore train to OPERABLE status.	~~6~~24 hours
	OR	
	G.2.1 Be in MODE 3.	~~12~~30 hours
	AND	
	G.2.2 Be in MODE 4.	~~18~~36 hours
H. One channel inoperable.	---------- **- NOTE -** The inoperable channel may be bypassed for up to 4~~1~~2 hours for surveillance testing of other channels. ----------	
	H.1 Place channel in trip.	~~6~~72 hours
	OR	
	H.2 Be in MODE 3.	~~12~~78 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. One Main Feedwater Pumps trip channel inoperable.	I.1 Restore channel to OPERABLE status. OR I.2 Be in MODE 3.	48 hours 54 hours
J. One channel inoperable.	---------- **- NOTE -** One ~~additional~~ channel may be bypassed for up to ~~4~~12 hours for surveillance testing. ---------- J.1 Place channel in bypass. OR J.2.1 Be in MODE 3. AND J.2.2 Be in MODE 5.	 ~~6~~72 hours ~~12~~78 hours ~~42~~108 hours
K. One or more channels inoperable.	K.1 Verify interlock is in required state for existing unit condition. OR K.2.1 Be in MODE 3. AND K.2.2 Be in MODE 4.	1 hour 7 hours 13 hours

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 MASTER RELAY TEST.	~~31~~92 days on a STAGGERED TEST BASIS
SR 3.3.2.4	Perform COT.	~~92~~184 days
SR 3.3.2.5	**- NOTE -** Verification of relay setpoints not required. Perform TADOT.	~~92~~184 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.6	Perform SLAVE RELAY TEST.	18 months (Unit 1) 92 days (Unit 2) OR ---------- **- NOTE -** Only applicable to Unit 2 provided a satisfactory contact loading analysis has been completed, and a satisfactory slave relay service life has been established, for the slave relay being tested. ---------- 12 months
SR 3.3.2.7	---------- **- NOTE -** Verification of setpoint not required. ---------- Perform TADOT.	18 months
SR 3.3.2.8	---------- - NOTE - This Surveillance shall include verification that the time constants are adjusted to the prescribed values. ---------- Perform CHANNEL CALIBRATION.	18 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.9	--- **- NOTE -** Not required to be performed for the turbine driven AFW pump until 24 hours after SG pressure is ≥ 600 psig. --- Verify ESFAS RESPONSE TIMES are within limit.	18 months on a STAGGERED TEST BASIS

3.3 INSTRUMENTATION

3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start and Bus Separation Instrumentation

LCO 3.3.5 The DG Start and Bus Separation instrumentation specified in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4,
When associated DG is required to be OPERABLE by LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

- NOTE -
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels inoperable.	A.1 Enter the applicable Condition(s) referenced in Table 3.3.5-1 for the affected channel(s).	Immediately
B. One or more Functions with one channel per bus inoperable.	**- NOTE -** The inoperable channel may be bypassed for up to ~~4~~12 hours for surveillance testing of other channels provided the corresponding instrument channels, electrical bus, and DG in the other train are OPERABLE. B.1 Place channel in trip.	~~6~~72 hours
C. One or more Functions with two channels per bus inoperable.	C.1 Restore one channel per bus to OPERABLE status.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One or more Functions with one channel per bus inoperable.	D.1 Restore inoperable channel to OPERABLE status.	1 hour
E. Required Action and associated Completion Time not met.	E.1 Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start or Bus Separation instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	---------- **- NOTE -** Verification of setpoint is not required. ---------- Perform TADOT.	~~92~~184 days
SR 3.3.5.2	Perform CHANNEL CALIBRATION.	18 months
SR 3.3.5.3	Verify ESF RESPONSE TIMES are within limit.	18 months on a STAGGERED TEST BASIS

Enclosure 1, Attachment B

Beaver Valley Power Station
Proposed Technical Specification Bases Changes

License Amendment Request 07-005

Technical Specification Bases changes are provided for Information Only
The following is a list of the affected pages:

Page		Page
B 3.3.1 – 35		B 3.3.2 – 33
B 3.3.1 – 36		B 3.3.2 – 34
		B 3.3.2 – 34a
B 3.3.1 – 39		B 3.3.2 – 34b
B 3.3.1 – 40		B 3.3.2 – 35
B 3.3.1 – 41		B 3.3.2 – 36
B 3.3.1 – 41a		B 3.3.2 – 37
B 3.3.1 – 41b		B 3.3.2 – 37a
B 3.3.1 – 41c		B 3.3.2 – 37b
		B 3.3.2 – 38
B 3.3.1 – 43		B 3.3.2 – 39
B 3.3.1 – 47		B 3.3.2 – 41
B 3.3.1 – 48		B 3.3.2 – 42 *
B 3.3.1 – 49 *		B 3.3.2 – 43
B 3.3.1 – 50		
B 3.3.1 – 51		B 3.3.2 – 48 *
		B 3.3.2 – 49
B 3.3.1 – 57		
		B 3.3.5 – 4
		B 3.3.5 – 5
		B 3.3.5 – 6
		B 3.3.5 – 7

* No Change. Page provided for context only.

Provided for Information Only.

BASES

ACTIONS (continued)

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

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

One NIS power range detector provides input to the Rod Control System and (for Unit 2 only) the SG Water Level Control System and, therefore, a two-out-of-four trip logic is used. 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~~72 hours allowed to place the inoperable channel in the tripped condition is justified in WCAP-~~10271-P-A~~14333-P-A, Rev. 1 (Reference 7).

In addition to placing the inoperable channel in the tripped condition, THERMAL POWER must be reduced to ≤ 75% RTP within ~~12~~78 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~~72 hours and the QPTR monitored once every 12 hours as 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~~ is consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. ~~Twelve~~ Seventy-eight hours are allowed to place the plant in MODE 3. The 78 hours Completion Time includes 72 hours for channel corrective maintenance, and an additional 6 hours for the MODE reduction required by Required Action D.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.

Provided for Information Only.

ACTIONS (continued)

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.

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux - Low,
- Overtemperature ΔT,
- Overpower ΔT,
- Power Range Neutron Flux - High Positive Rate,
- 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-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The ~~6~~72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 7.

If the inoperable 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 412 hours while performing routine surveillance testing of the other channels. The 412 hour time limit is justified in Reference 7.

Provided for Information Only.

ACTIONS (continued)

an OPERABLE status, action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour.

K.1 and K.2

Condition K applies to the following reactor trip Functions:

- Pressurizer Pressure - Low,
- Pressurizer Water Level - High,
- Reactor Coolant Flow - Low,
- RCP Breaker Position,
- Undervoltage RCPs, and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within ~~6~~72 hours. For the Pressurizer Pressure - Low, Pressurizer Water Level - High, Undervoltage RCPs, Underfrequency RCPs, and RCP Breaker Position trip Functions, placing the channel in the tripped condition when above the P-7 setpoint results in a partial trip condition requiring only one additional channel to initiate a reactor trip. For the Reactor Coolant Flow - Low (Two Loop) trip Function, placing the channel in the tripped condition when above the P-8 setpoint results in a partial trip condition in one loop requiring only one additional channel in the same loop to initiate a low flow signal for that loop. For the latter trip Function, two tripped channels in two RCS loops are required to initiate a reactor trip when below the P-8 setpoint and above the P-7 setpoint. The pressurizer pressure low Function and RCS flow related Functions do not have to be OPERABLE below the P-7 setpoint because there is insufficient heat production to generate DNB conditions below the P-7 setpoint. The pressurizer water level Function is not required OPERABLE below the P-7 setpoint, because transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions. The ~~6~~72 hours allowed to place the channel in the tripped condition is justified in Reference 7. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

Provided for Information Only.

ACTIONS (continued)

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 K.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4~~1~~12 hours while performing routine surveillance testing of the other channels. The 4~~1~~12 hour time limit is justified in Reference 7.

L.1 and L.2

Condition L applies 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. 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 for Turbine Trip on Low Fluid Oil Pressure. Reference 8 justifies the 72 hour Completion Time allowed to place an inoperable channel in the tripped condition for Turbine Trip on Turbine Stop Valve Closure.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4~~1~~12 hours while performing routine surveillance testing of the other channels. The 4~~1~~12 hour time limit is justified in Reference 7 for Turbine Trip on Low Fluid Oil Pressure, and Reference 8 for Turbine Trip on Turbine Stop Valve Closure.

M.1 and M.2

Condition M 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 M.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of ~~6~~24 hours (Required Action M.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 7.

ACTIONS (continued)

The Completion Time of 6 hours (Required Action M.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 time specified in the Note is an exception to the 6 hour Completion Time that provides a delay period prior to starting the Completion Time.~~

Planned Maintenance and Tier 2 Restrictions

Consistent with the NRC Safety Evaluation (SE) requirements for WCAP-14333-P-A, Rev. 1 (Reference 7), Tier 2 insights must be included in the decision making process before removing an RTS logic train from service and implementing the extended (risk-informed) Completion Time for an RTS logic train approved in Reference 10. These "Tier 2 restrictions" are considered to be necessary to avoid risk significant plant configurations during the time an RTS logic train is inoperable.

Entry into Condition M for an inoperable RTS logic train is not a typical, pre-planned evolution during the MODES of Applicability for this equipment, other than when necessary for surveillance testing. Since Condition M may be entered due to equipment failure, some of the Tier 2 restrictions discussed below may not be met at the time of Condition M entry. In addition, it is possible that equipment failure may occur after the RTS logic train is removed from service for surveillance testing or planned maintenance, such that one or more of the required Tier 2 restrictions are no longer met. In cases of equipment failure, the programs and procedures in place to address the requirements of 10CFR 50.65(a)(4) require assessment of the emergent condition with appropriate actions taken to manage risk. Depending on the specific situation, these actions could include activities to restore the inoperable logic train and exit the Condition, or to fully implement the Tier 2 restrictions, or to perform a unit shutdown, as appropriate from a risk management perspective.

The following Tier 2 restrictions on concurrent removal of certain equipment will be implemented as described above when entering Condition M when an RTS logic train is inoperable:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable.

ACTIONS (continued)

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained. Note that Technical Specification 3.5.2, ECCS Operating, ensures that this restriction is met. Therefore, this restriction does not have to be implemented by a separate procedure or program.
- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable.
- Activities on electrical systems (AC and DC power) and cooling systems (service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable. That is, one complete train of a function that supports a complete train of a function noted above must be available.

N.1 and N.2

Condition N 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~~24 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 24 hour Completion Time is justified in Reference 9. 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 results in ACTION C entry while RTB(s) are inoperable.

The Required Actions have been modified by ~~two~~ a Notes. The Note ~~1~~ allows one train to be bypassed for up to ~~2~~4 hours for surveillance testing, provided the other train is OPERABLE. ~~Note 2 allows one RTB to be bypassed for up to 2 hours for maintenance on the undervoltage or shunt trip mechanisms if the other RTB train is OPERABLE.~~ The 4 hours allowed to bypass a train is justified in Reference 9. ~~The time specified in these Notes is an exception to the 1 hour Completion Time that provides a delay period prior to starting the Completion Time.~~

ACTIONS (continued)

Planned Maintenance and Tier 2 Restrictions

Consistent with the NRC Safety Evaluation (SE) requirements in WCAP-15376-P-A, Rev. 1 (Reference 9), Tier 2 insights must be included in the decision making process before removing an RTB train from service and implementing the extended (risk-informed) Completion Time for an RTB train approved in Reference 10. These "Tier 2 restrictions" are considered to be necessary to avoid risk significant plant configurations during the time an RTB train is inoperable.

Entry into Condition N for an inoperable RTB train is not a typical, pre-planned evolution during the MODES of Applicability for this equipment, other than when necessary for surveillance testing. Since Condition N may be entered due to equipment failure, some of the Tier 2 restrictions discussed below may not be met at the time of Condition N entry. In addition, it is possible that equipment failure may occur after the RTB train is removed from service for surveillance testing or planned maintenance, such that one or more of the required Tier 2 restrictions are no longer met. In cases of equipment failure, the programs and procedures in place to address the requirements of 10CFR 50.65(a)(4) require assessment of the emergent condition with appropriate actions taken to manage risk. Depending on the specific situation, these actions could include activities to restore the inoperable RTB train and exit the Condition, or to fully implement the Tier 2 restrictions, or to perform a unit shutdown, as appropriate from a risk management perspective.

The following Tier 2 restrictions on concurrent removal of certain equipment will be implemented as described above when entering Condition N when an RTB train is inoperable:

- The probability of failing to trip the reactor on demand will increase when a RTB is removed from service, therefore, systems designed for mitigating an ATWS event should be maintained available. RCS pressure relief (pressurizer PORVs and safety valves), auxiliary feedwater flow (for RCS heat removal), AMSAC, and turbine trip are important to ATWS mitigation. Therefore, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a RTB is inoperable.

ACTIONS (continued)

- Due to the increased dependence on the available reactor trip train when one logic train is unavailable, activities that degrade other components of the RTS, including master relays or slave relays, and activities that cause analog channels to be unavailable, should not be scheduled when a logic train is inoperable.

- Activities on electrical systems (AC and DC power) that support the systems or functions listed in the first two bullets should not be scheduled when a RTB is inoperable.

O.1 and O.2

Condition O applies to the P-6 and P-10 interlocks. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 3 within the next 6 hours. Verifying the interlock status manually accomplishes the interlock's Function. The interlock status may be verified by observation of the associated permissive annunciator/status window(s). 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.

Provided for Information Only.

ACTIONS (continued)

R.1

Condition R applies to one inoperable Power Range Neutron Flux - Low channel in MODE 2 with $k_{eff} < 1.0$, and all RCS cold leg temperatures ≥ 500°F, and RCS boron concentration ≤ the ARO critical boron concentration when the Rod Control System is capable of rod withdrawal, or one or more rods not fully inserted, and in MODE 3 with all RCS cold leg temperatures ≥ 500°F, and the RCS boron concentration is ≤ the ARO critical boron concentration when the Rod Control System is capable of rod withdrawal, or one or more rods are not fully inserted. 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 a one-out-of-three logic for actuation of this reactor trip function. The ~~6~~72 hours to place the inoperable channel in the tripped condition is justified in Reference 7.

The Required Action is modified by a Note. The Note allows placing an 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.

S.1.1, S.1.2, and S.2

If the inoperable channel can not be placed in the tripped condition within the specified Completion Time, or if two or more channels are inoperable, action must be initiated immediately to fully insert all rods, and to make the rods incapable of rod withdrawal. This action will preclude an uncontrolled RCCA bank withdrawal accident from occurring.

Required Action S.2 provides an alternative to Required Actions S.1.1 and S.1.2. If the inoperable channel can not be placed in the tripped condition within the specified Completion Time, or if two or more channels are inoperable, action must be initiated to borate the RCS to > the ARO critical boron concentration. Borating the RCS to > the ARO critical boron concentration would provide sufficient SHUTDOWN MARGIN, if an uncontrolled RCCA bank withdrawal accident were to occur.

Provided for Information Only.

BASES

SURVEILLANCE REQUIREMENTS (continued)

For each operating cycle, the initial channel normalization is performed in accordance with SR 3.3.1.9. Subsequent periodic verification at a Frequency of every 31 EFPD is adequate to ensure the NIS channels remain calibrated. 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. A successful test of any required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements.

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 3.3.1.12. The bypass breaker test shall include a local manual 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 justified in Reference 9.~~adequate. It is based on industry operating experience, considering instrument reliability and operating history data.~~

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The 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 condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function, including operation of the P-7 permissive which is a logic function only. The Frequency of every ~~31~~92 days on a STAGGERED TEST BASIS is justified in Reference 9.~~adequate. It is based on industry operating experience, considering instrument reliability and operating history data.~~

Provided for Information Only.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

SR 3.3.1.6 is the performance of a COT every ~~92~~184 days.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. A successful test of any required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements.

Setpoints must be within the Allowable Values specified in Table 3.3.1-1 (excluding time constants which are verified during CHANNEL CALIBRATIONS).

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

For certain RTS Functions the required COT (SR 3.3.1.6 specified in Table 3.3.1-1) is modified by Notes (k) and (l). These Notes specify additional requirements for the affected instrument channels.

Note (k) specifies the following:

- If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service, and

- If the "as-found" instrument channel setpoint is not conservative with respect to the Allowable Value, the channel shall be declared inoperable.

The evaluation of channel performance required by Note (k) involves an assessment to verify the channel will continue to behave in accordance with design basis assumptions, and to ensure confidence in the channel performance prior to returning the channel to service. In addition, if the "as found" trip setpoint value is non-conservative with respect to the Allowable Value, or is found to be outside of the two sided predefined acceptance criteria band on either side of the nominal trip setpoint, the affected channel will be evaluated under the corrective action program.

No change. Page included for context only.

Provided for Information Only.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Note (l) specifies the following:

- The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the nominal trip setpoint, or a value that is more conservative than the nominal trip setpoint; otherwise, the channel shall be declared inoperable, and

- The nominal trip setpoint and the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band are specified in a document incorporated by reference into the Updated Final Safety Analysis Report.

For BVPS, the document containing the nominal trip setpoint, the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band is the LRM.

For the RTS Functions with a COT modified by Note (l), the Note requires that the instrument channel setpoint be reset to a value within the "as left" setpoint tolerance band on either side of the nominal trip setpoint or to a value that is more conservative than the nominal trip setpoint. The conservative direction is established by the direction of the inequality sign applied to the associated Allowable Value. Setpoint restoration and post-test verification assure that the assumptions in the plant setpoint methodology are satisfied in order to protect the safety analysis limits. If the channel can not be reset to a value within the required "as left" setpoint tolerance band on either side of the nominal trip setpoint, or to a value that is more conservative than the nominal trip setpoint (if required based on plant conditions) the channel is declared inoperable and the applicable ACTION is entered.

For the RTS Functions with a COT modified by Notes (k) and (l), the "as found" and "as left" setpoint data obtained during COTs or CHANNEL CALIBRATIONS are programmatically trended to demonstrate that the rack drift assumptions used in the plant setpoint methodology are valid. If the trending evaluation determines that a channel is performing inconsistent with the uncertainty allowances applicable to the periodic surveillance test being performed, the channel is evaluated under the corrective action program. If the channel is not capable of performing its specified safety function, it is declared inoperable.

Provided for Information Only.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6 is modified by a Note that provides a 12 hour delay in the requirement to perform this Surveillance for source range instrumentation after decreasing power below the P-6 interlock setpoint. 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 3.3.1.6 is no longer required to be performed. If the unit is to be in MODE 2 below the P-6 setpoint or in MODE 3 with the RTBs closed for > 12 hours this Surveillance must be performed prior to 12 hours after decreasing power below the P-6 setpoint.

The Frequency of ~~92~~184 days is justified in Reference ~~7~~9.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT as described in SR 3.3.1.6, except it is modified by a Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit condition. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within ~~92~~184 days of the Frequencies prior to reactor startup and 12 hours after reducing power below P-10. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the intermediate and power range low instrument channels. The Frequency of 12 hours after reducing power below P-10 (applicable to intermediate and power range low channels) 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~~184 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup and 12 hours after reducing power below P-10. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 for more than 12 hours, then the testing required by this surveillance must be performed prior to the expiration of the time limit. Twelve 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 intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10) for periods > 12 hours.

The Frequency of 184 days is justified in Reference 9.

Provided for Information Only.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.8

SR 3.3.1.8 is the performance of a TADOT and is performed every ~~92~~184 days, as justified in Reference ~~7~~10. A successful test of any required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements.

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 3.3.1.9

SR 3.3.1.9 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 (normalized), the channels are declared inoperable. This Surveillance is performed at BOL to normalize the excore channel f(ΔI) input to the overtemperature ΔT Function for each new operating cycle. The Surveillance is assigned to both the Power Range Neutron Flux High and OTΔT RTS Functions to assure all 4 NIS channels are initially normalized to the new core.

A Note modifies SR 3.3.1.9. The Note states that this Surveillance is required only if reactor power is ≥ 50% RTP and that 7 days are allowed for performing the Surveillance after reaching 50% RTP.

The Frequency of once per fuel cycle is adequate to establish the initial cycle-specific calibration of the excore channels. It is based on industry operating experience, considering instrument reliability and the performance of SR 3.3.1.3 every 31 EFPD which verifies the excore channels remain within the required calibration tolerance.

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.

Provided for Information Only.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.14 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.

REFERENCES

1. Westinghouse Setpoint Methodology for Protection Systems, WCAP-11419, Rev. 5 (Unit 1) and WCAP-11366, Rev. 7 (Unit 2).

2. UFSAR, Chapter 7 (Unit 1 and Unit 2).

3. UFSAR Chapter 14 (Unit 1) and UFSAR Chapter 15 (Unit 2).

4. IEEE-279-1971.

5. 10 CFR 50.49.

6. Westinghouse Nuclear Safety Advisory Letter NSAL-00-016, Rod Withdrawal from Subcritical Protection in Lower Modes, December 4, 2000.

7. ~~WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.~~ WCAP-14333-P-A, Rev. 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.

8. WOG-06-17, "WCAP-10271-P-A Justification for Bypass Test Time and Completion Time Technical Specification Changes for Reactor Trip on Turbine Trip," June 20, 2006.

9. 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," March 2003.

10. License Amendments approving License Amendment Request 07-005.

Reviewer Note. This reference is a place holder that will be changed to the License Amendment number when it is issued.

Provided for Information Only.

ACTIONS (continued)

specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each manual Function, and the low probability of an event occurring during this interval. In the case of the Automatic Actuation Logic for the Containment sump switchover, the Completion Time is reasonable considering that the other automatic actuation logic train is OPERABLE and that manual actions may be taken to align the required equipment to the containment sump. 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 (54 hours total time) and in MODE 5 within an additional 30 hours (84 hours total time). The allowable Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

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

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI,
- Containment Spray,
- Phase A Isolation, and
- Phase B Isolation.

This Action Condition is intended to address an inoperability of the actuation logic or relays associated with an ESFAS train that affects the integrated ESFAS response to an actuation signal. The ~~relatively short~~ Completion Time of this ACTION (~~6~~24 hours) is based on the assumption that multiple ESF components within a train are affected by the failure of the actuation logic or relays. Therefore, the ~~short~~ Completion Time of this Action is appropriate and applicable whenever more than one ESF System is affected by the inoperable train of logic or relays.

However, if one or more inoperable actuation relays in an ESFAS train only affect a single ESF component or system, the applicable Actions Condition for the affected ESF component or system should be entered and the ~~relatively short~~ Completion Time of this Action Condition is not appropriate or applicable.

Provided for Information Only.

BASES

ACTIONS (continued)

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 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 7. 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 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 assumption of WCAP-10271-P-A (Reference 5) that 4 hours is the average time required to perform ~~channel~~ train surveillance.

Planned Maintenance and Tier 2 Restrictions

Consistent with the NRC Safety Evaluation (SE) requirements for WCAP-14333-P-A, Rev. 1 (Reference 7), Tier 2 insights must be included in the decision making process before removing a logic train from service and implementing the extended (risk-informed) Completion Time for a logic train approved in Reference 9. These "Tier 2 restrictions" are considered to be necessary to avoid risk significant plant configurations during the time a logic train is inoperable.

Entry into Condition C for an inoperable logic train is not a typical, pre-planned evolution during the MODES of Applicability for this equipment, other than when necessary for surveillance testing. Since Condition C may be entered due to equipment failure, some of the Tier 2 restrictions discussed below may not be met at the time of Condition C entry. In addition, it is possible that equipment failure may occur after the logic train is removed from service for surveillance testing or planned maintenance, such that one or more of the required Tier 2 restrictions are no longer met. In cases of equipment failure, the programs and procedures inn place to address the requirements of 10CFR50.65(a)(4) require assessment of

Provided for Information Only.

ACTIONS (continued)

the emergent condition with appropriate actions taken to manage risk. Depending on the specific situation, these actions could include activities to restore the inoperable logic train and exit the Condition, or to fully implement the Tier 2 restrictions, or to perform a unit shutdown, as appropriate from a risk management perspective.

The following Tier 2 restrictions on concurrent removal of certain equipment will be implemented as described above when entering Condition C when a logic train is inoperable:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable.
- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained. Note that Technical Specification 3.5.2, ECCS Operating, ensures that this restriction is met. Therefore, this restriction does not have to be implemented by a separate procedure or program.
- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable.
- Activities on electrical systems (AC and DC power) and cooling systems (service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable. That is, one complete train of a function that supports a complete train of a function noted above must be available

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

Condition D applies to:

- Containment Pressure - High,
- Pressurizer Pressure - Low,
- Steam Line Pressure - Low,
- Containment Pressure - Intermediate - High High,
- Steam Line Pressure - Negative Rate - High,

Provided for Information Only.

ACTIONS (continued)

- SG Water level - Low Low, ~~and~~
- SG Water level - High High (P-14), and
- RWST Level Low (Unit 1 only).

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. For the Functions listed above, other than RWST Level Low, the 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition is justified in Reference 7. For RWST Level Low, the 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition is justified in Reference 9.

Provided for Information Only.

BASES

ACTIONS (continued)

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~~1~~12 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~~ The 12 hours allowed for testing, are justified in References ~~5~~7 and 9.

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

Condition E applies to:

- Containment Spray Containment Pressure - High High, and
- Containment Phase B 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 72 hours allowed to restore the channel to OPERABLE status or to place it in the bypassed condition is justified in Reference 7. The Completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable

Provided for Information Only.

ACTIONS (continued)

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 412 hours for surveillance testing. Placing a second channel in the bypass condition for up to 412 hours for testing purposes is acceptable based on the results of Reference ~~5~~7.

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

Condition F applies to:

- The Unit 2 Manual Initiation of Steam Line Isolation, and
- P-4 Interlock.

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, G.2.1, and G.2.2

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

This Action Condition is intended to address an inoperability of the actuation logic or relays associated with an ESFAS train that affects the integrated ESFAS response to an actuation signal. The ~~relatively short~~

Provided for Information Only.

BASES

ACTIONS (continued)

Completion Time of this ACTION (~~6~~24 hours) is based on the assumption that multiple ESF components within a train are affected by the failure of the actuation logic or relays. Therefore, the ~~short~~ Completion Time of this Action is appropriate and applicable whenever more than one ESF System is affected by the inoperable train of logic or relays.

However, if one or more inoperable actuation relays in an ESFAS train only affect a single ESF component or system, the applicable Actions Condition for the affected ESF component or system should be entered and the ~~relatively short~~ Completion Time of this Action Condition is not appropriate or applicable.

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 7. 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 (Reference 5) assumption that 4 hours is the average time required to perform ~~channel~~ train surveillance.

Planned Maintenance and Tier 2 Restrictions

Consistent with the NRC Safety Evaluation (SE) requirements for WCAP-14333-P-A, Rev. 1 (Reference 7), Tier 2 insights must be included in the decision making process before removing a logic train from service and implementing the extended (risk-informed) Completion Time for a logic train approved in Reference 9. These "Tier 2 restrictions" are considered to be necessary to avoid risk

Provided for Information Only.

BASES

ACTIONS (continued)

significant plant configurations during the time a logic train is inoperable.

Entry into Condition G for an inoperable logic train is not a typical, pre-planned evolution during the MODES of Applicability for this equipment, other than when necessary for surveillance testing. Since Condition G may be entered due to equipment failure, some of the Tier 2 restrictions discussed below may not be met at the time of Condition G entry. In addition, it is possible that equipment failure may occur after the logic train is removed from service for surveillance testing or planned maintenance, such that one or more of the required Tier 2 restrictions are no longer met. In cases of unplanned equipment failure, the programs and procedures in place to address the requirements of 10CFR 50.65(a)(4) require assessment of the emergent condition with appropriate actions taken to manage risk. Depending on the specific situation, these actions could include activities to restore the inoperable logic train and exit the Condition, or to fully implement the Tier 2 restrictions, or to perform a unit shutdown, as appropriate from a risk management perspective.

The following Tier 2 restrictions on concurrent removal of certain equipment will be implemented as described above when entering Condition G when a logic train is inoperable:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable.
- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained. Note that Technical Specification 3.5.2, ECCS Operating, ensures that this restriction is met. Therefore, this restriction does not have to be implemented by a separate procedure or program.
- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable.
- Activities on electrical systems (AC and DC power) and cooling systems (service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable. That is, one complete train of a function that supports a complete train of a function noted above must be available.

Provided for Information Only.

BASES

ACTIONS (continued)

H.1 and H.2

Condition H applies to:

- Undervoltage Reactor Coolant Pump.

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. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped

Provided for Information Only.

ACTIONS (continued)

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 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~~1~~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~~1~~12 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference ~~5~~7.

I.1 and I.2

Condition I applies to the AFW pump start on trip 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, 48 hours are allowed to return it to an OPERABLE status. If the function cannot be returned to an OPERABLE status, 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. The allowance of 48 hours to return the train to an OPERABLE status is justified in Reference 5.

J.1, J.2.1, and J.2.2

Condition J applies to:

- RWST Level Extreme Low Coincident with Safety Injection.

RWST Level Extreme Low Coincident with SI provides actuation of switchover to the containment sump. Note that this Function requires the bistables to energize to perform their required action. The failure of up to two channels will not prevent the operation of this Function. However, placing a failed channel in the tripped condition could result in a premature switchover to the sump, prior to the injection of the minimum volume from the RWST. Placing the inoperable channel in bypass results in a two-out-of-three logic configuration, which satisfies

Provided for Information Only.

BASES

ACTIONS (continued)

the requirement to allow another failure without disabling actuation of the switchover when required. Restoring the channel to OPERABLE status or placing the inoperable channel in the bypass condition within ~~6~~72 hours is sufficient to ensure 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 low). If the channel cannot be returned to OPERABLE status or placed in the bypass condition within ~~6~~72 hours, the unit must be brought to MODE 3 within the following 6 hours and MODE 5 within the next 30 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 5, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above.

The Required Actions are modified by a Note that allows placing a ~~second~~ channel in the bypass condition for up to 412 hours for surveillance testing. The ~~6~~72 hours to place a channel in bypass and the total of ~~12~~78 hours to reach MODE 3 and 412 hours for a second channel to be bypassed are justified in Reference 9.~~is acceptable based on the results of Reference 5.~~

K.1, K.2.1, and K.2.2

Condition K applies to the P-11 and P-12 interlocks.

With one or more channels inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock.

Determination must be made within 1 hour and may be made by observation of the associated permissive annunciator window(s) (bistable status lights or computer checks). The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of these interlocks.

Provided for Information Only.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.2

SR 3.3.2.2 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 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 ~~31~~92 days on a STAGGERED TEST BASIS is justified in Reference 8.~~adequate. It is based on industry operating experience, considering instrument reliability and operating history data.~~

SR 3.3.2.3

SR 3.3.2.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is 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 Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 8. The time allowed for the testing (4 hours) ~~and the surveillance interval are~~ is justified in Reference 5.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1 (excluding time constants which are verified during CHANNEL CALIBRATIONS). A successful test of any required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

No change. Page included for context only.

Provided for Information Only.

BASES

SURVEILLANCE REQUIREMENTS (continued)

For certain ESFAS Functions the required COT (SR 3.3.2.4 specified in Table 3.3.2-1) is modified by Notes (e) and (f). These Notes specify additional requirements for the affected instrument channels.

Note (e) specifies the following:

- If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service, and

- If the "as-found" instrument channel setpoint is not conservative with respect to the Allowable Value, the channel shall be declared inoperable.

The evaluation of channel performance required by Note (e) involves an assessment to verify the channel will continue to behave in accordance with design basis assumptions, and to ensure confidence in the channel performance prior to returning the channel to service. In addition, if the "as found" trip setpoint value is non-conservative with respect to the Allowable Value, or is found to be outside of the two sided predefined acceptance criteria band on either side of the nominal trip setpoint, the affected channel will be evaluated under the corrective action program.

Note (f) specifies the following:

- The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the nominal trip setpoint, or a value that is more conservative than the nominal trip setpoint; otherwise, the channel shall be declared inoperable, and

- The nominal trip setpoint and the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band are specified in a document incorporated by reference into the Updated Final Safety Analysis Report.

For BVPS, the document containing the nominal trip setpoint, the methodology used to determine the nominal trip setpoint, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band is the LRM.

Provided for Information Only.

BASES

SURVEILLANCE REQUIREMENTS (continued)

For the ESFAS Functions with a COT modified by Note (f), the Note requires that the instrument channel setpoint be reset to a value within the "as left" setpoint tolerance band on either side of the nominal trip setpoint or to a value that is more conservative than the nominal trip setpoint. The conservative direction is established by the direction of the inequality sign applied to the associated Allowable Value. Setpoint restoration and post-test verification assure that the assumptions in the plant setpoint methodology are satisfied in order to protect the safety analysis limits. If the channel can not be reset to a value within the required "as left" setpoint tolerance band on either side of the nominal trip setpoint, or to a value that is more conservative than the nominal trip setpoint (if required based on plant conditions) the channel is declared inoperable and the applicable ACTION is entered.

For the ESFAS Functions with a COT modified by Notes (e) and (f), the "as found" and "as left" setpoint data obtained during COTs or CHANNEL CALIBRATIONS are programmatically trended to demonstrate that the rack drift assumptions used in the plant setpoint methodology are valid. If the trending evaluation determines that a channel is performing inconsistent with the uncertainty allowances applicable to the periodic surveillance test being performed, the channel is evaluated under the corrective action program. If the channel is not capable of performing its specified safety function, it is declared inoperable.

The Frequency of ~~92~~184 days is justified in Reference ~~5~~8.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a TADOT every ~~92~~184 days. This test is a check of the Undervoltage RCP Function. The Function is tested up to the SSPS logic circuit. A successful test of any required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements.

The SR is modified by a Note that excludes verification of setpoints for relays. Relay setpoints require elaborate bench calibration and are verified during CHANNEL CALIBRATION. The Frequency ~~is adequate. It is based on industry operating experience, considering instrument reliability and operating history data~~of 184 days is justified in Reference 9.

SURVEILLANCE REQUIREMENTS (continued)

WCAP-14036-P, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," and WCAP-15413, "Westinghouse 7300A ASIC-Based Replacement Module Licensing Summary Report" provide the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. The allocations for sensor, signal conditioning, and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in the WCAP may be replaced without verification testing. One example where response time could be affected is replacing the sensing assembly of a transmitter. WCAP-15413 provides bounding response times where 7300 cards have been replaced with ASICs cards.

ESF RESPONSE TIME tests are conducted on an 18 month STAGGERED TEST BASIS. Testing of the final actuation devices, which make up the bulk of the response time, is included in the testing of each channel. The final actuation device in one train is tested with each channel. Therefore, staggered testing results in response time verification of these devices every 18 months. The 18 month Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

This SR is modified by a Note that clarifies that the turbine driven AFW pump is tested within 24 hours after reaching 600 psig in the secondary side of the SGs.

REFERENCES

1. UFSAR Chapter 14 (Unit 1) and UFSAR Chapter 15 (Unit 2).
2. IEEE-279-1971.
3. Westinghouse Setpoint Methodology for Protection Systems, WCAP-11419, Rev. 5 (Unit 1) and WCAP-11366, Rev. 7 (Unit 2).
4. 10 CFR 50.49.
5. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
6. WCAP-15887, Revision 2, "Probabilistic Risk Analysis of the Slave Relay Surveillance Test Interval Extension for Beaver Valley Power Station, Unit 2," December 2002.

Provided for Information Only.

BASES

REFERENCES (continued)

Reviewer Note. This reference is a place holder that will be changed to the License Amendment number when it is issued.

7. WCAP-14333-P-A, Rev. 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.

8. 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," March 2003.

9. License Amendments approving License Amendment Request 07-005.

Provided for Information Only.

BASES

APPLICABILITY

The LOP Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function for a loss of voltage or degraded voltage condition on an emergency bus.

ACTIONS

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function specified in Table 3.3.5-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to all LOP instrument functions specified in Table 3.3.5-1. Condition A addresses the situation where one or more channels for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.5-1 and to take the applicable Required Actions for the LOP functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1

Condition B applies to the LOP Functions with one loss of voltage or one degraded voltage channel per bus inoperable. The Condition is applicable to a single inoperable channel on one bus or a single inoperable channel on each bus.

If one channel is inoperable, Required Action B.1 requires that channel to be placed in trip within ~~6~~72 hours. With a channel in trip, the LOP instrumentation channels are configured to provide a one-out-of-one logic to initiate the LOP protection function.

A Note is added to allow bypassing an inoperable channel for up to 4~~1~~12 hours for surveillance testing of other channels provided the corresponding instrument channels, electrical bus, and DG in the other

Provided for Information Only.

BASES

ACTIONS (continued)

train are OPERABLE. This allowance is made where bypassing the channel does not cause an actuation and where the other electrical train remains OPERABLE to supply emergency power if required.

The specified Completion Time and time allowed for bypassing one channel are justified in Reference 4.~~reasonable considering the time necessary to accomplish the action in a safe manner and the low probability of an event occurring during these intervals.~~

C.1

Condition C applies when more than one loss of voltage or more than one degraded voltage channel per bus are inoperable. The Condition is applicable to two inoperable channels on one bus or two inoperable channels on each bus.

Required Action C.1 requires restoring one channel per bus to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP instrument actuation during this interval.

D.1

Condition D applies when one loss of voltage channel per bus is inoperable and is applicable only to those LOP Functions on Table 3.3.5-1 with a single loss of voltage channel per bus. The Condition is applicable to a single inoperable channel on one bus or a single inoperable channel on each bus.

Required Action D.1 requires restoring the inoperable channel to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring a LOP instrument actuation during this interval.

E.1

Condition E applies to each of the LOP instrument Functions when the Required Action and associated Completion Time for Condition A, B, C, or D are not met.

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources - Operating," or LCO 3.8.2, "AC Sources - Shutdown," for the DG made inoperable by failure of the LOP instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety.

Provided for Information Only.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT. A successful test of any required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification Surveillance Requirements. This test is performed every ~~92~~184 days. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. The Frequency is justified in Reference 4.~~based on the known reliability of the relays and controls and has been shown to be acceptable through operating experience.~~

The SR is modified by a Note that excludes verification of setpoint from the TADOT. The SR applies to the loss of voltage and degraded voltage relays for the 4160 V and 480 V emergency buses and setpoint verification requires removal of the relay and a bench calibration. Therefore, relay calibration and setpoint verification are accomplished during the 18 month CHANNEL CALIBRATION.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay, as specified in the LRM.

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. For Unit 1 only, the time delay specified for the 4160 V emergency bus loss of voltage DG start relay, includes auxiliary relay times.

The Frequency of 18 months is based on operating experience and consistency with the typical industry refueling cycle and is justified by the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

Provided for Information Only.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.3

This SR ensures the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. The response time acceptance criteria for instrument channels with a required response time are specified in the LRM. 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 reaches the required functional state. Response time may be verified by any series of sequential, overlapping or total channel measurement such that the entire response time is measured.

The Bases for Surveillance Requirement 3.3.2.9 in LCO 3.3.2, "ESFAS Instrumentation" contains a more detailed description of how the required response time verification may be accomplished. The SR 3.3.2.9 Bases is applicable to SR 3.3.5.3 including the Unit 2 option to use the summation of allocated response times.

ESF RESPONSE TIME verifications are conducted on an 18 month STAGGERED TEST BASIS. The final actuation device response time, which makes up the bulk of the total response time, is included in the verification of each channel. The 18 month Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

REFERENCES

1. Unit 1 and Unit 2 UFSAR, Chapter 8.
2. Westinghouse Setpoint Methodology for Protection Systems, WCAP-11419, Rev. 5 (Unit 1) and WCAP-11366, Rev. 7 (Unit 2).
3. UFSAR, Chapter 14 for Unit 1 and Chapter 15 for Unit 2.
4. License Amendments approving License Amendment Request 07-005.

Reviewer Note. This reference is a place holder that will be changed to the License Amendment number when it is issued.

Enclosure 2

Affidavit CAW-07-2309

Westinghouse

Westinghouse Electric Company
Nuclear Services
P.O. Box 355
Pittsburgh, Pennsylvania 15230-0355
USA

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555-0001

Direct tel: (412) 374-4643
Direct fax: (412) 374-4011
e-mail: greshaja@westinghouse.com

Our ref: CAW-07-2309

July 31, 2007

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: WCAP-15376 Implementation Guideline, "Approach to Address the Conditions and Limitations in the NRC's Safety Evaluation" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-07-2309 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, 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 Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by FirstEnergy Nuclear Operating Company (FENOC).

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-07-2309, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: Jon Thompson (NRC O-7E1A)

bcc: J. A. Gresham (ECE 4-7A) 1L
R. Bastien, 1L (Nivelles, Belgium)
C. Brinkman, 1L (Westinghouse Electric Co., 12300 Twinbrook Parkway, Suite 330, Rockville, MD 20852)
RCPL Administrative Aide (ECE 4-7A) 1L, 1A (letter and affidavit only)

CAW-07-2309

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared J. A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Sworn to and subscribed before me
this 31st day of July, 2007

Sharon L. Markle
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Sharon L. Markle, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Jan. 29, 2011
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory Compliance and Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse "Application for Withholding" accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in WCAP-15376 Implementation Guideline, "Approach to Address the Conditions and Limitations in the NRC's Safety Evaluation" (Proprietary) on behalf of the Pressurized Water Reactor Owners Group (PWROG), being transmitted by FirstEnergy Nuclear Operating Company (FENOC) letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted for use by the Pressurized Water Reactor Owners Group for Beaver Valley Units 1 and 2 is expected to be applicable for other licensee submittals.

This information is part of that which will enable Westinghouse to:

(a) Provide risk-informed assessment of the RTS and ESFAS to extend the interval for surveillance testing.

(b) Provide licensing defense services.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for purposes of extending surveillance testing intervals.

(b) Westinghouse can sell support and defense of extending surveillance testing intervals.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar assessments and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

COPYRIGHT NOTICE

The reports transmitted herewith each bear a Westinghouse copyright notice. The NRC is permitted to make the number of copies of the information contained in these reports which are necessary for its internal use in connection with generic and plant-specific reviews and approvals as well as the issuance, denial, amendment, transfer, renewal, modification, suspension, revocation, or violation of a license, permit, order, or regulation subject to the requirements of 10 CFR 2.390 regarding restrictions on public disclosure to the extent such information has been identified as proprietary by Westinghouse, copyright protection notwithstanding. With respect to the non-proprietary versions of these reports, the NRC is permitted to make the number of copies beyond those necessary for its internal use which are necessary in order to have one copy available for public viewing in the appropriate docket files in the public document room in Washington, DC and in local public document rooms as may be required by NRC regulations if the number of copies submitted is insufficient for this purpose. Copies made by the NRC must include the copyright notice in all instances and the proprietary notice if the original was identified as proprietary.

Enclosure 4

WCAP-15376 Implementation Guideline, "Approach to Address the Conditions and Limitations in the NRC's Safety Evaluation" (Non-Proprietary)

Safety Evaluation Condition 1 for WCAP-14333-P-A and WCAP-15376-P-A

In order to address Safety Evaluation (SE) Condition 1 for both WCAPs, Westinghouse issued implementation guidelines for licensees to confirm the analyses are applicable to their plant.

Confirm Applicability

[

]a,c

Containment Failure Assessment

[

]a,c

Note that SE Condition 2 for WCAP-14333 and WCAP-15376 and WCAP-15376 SE Condition 3 do not pertain to the Topical Report Applicability Determination for BVPS Units 1 and 2 and therefore, are not discussed in this enclosure.

Safety Evaluation Condition 4 for WCAP-15376-P-A

[

]a,c

Note that WCAP-15376 SE Condition 5 does not pertain to the Topical Report Applicability Determination for BVPS Units 1 and 2 and therefore, is not discussed in this enclosure.

Table 1
WCAP-14333 Implementation Guidelines: Applicability of the Analysis General Parameters to BVPS Units 1 and 2

Parameter	WCAP-14333 Analysis Assumptions	Plant Specific Parameter
Logic Cabinet Type (1)	SSPS or Relay	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	Unit 1: 18 months Unit 2: 3 months
• Reactor trip breakers	2 months	2 months
Analog Channel Calibrations (3)		
• Done at-power	Yes	Yes
• Interval	18 months	18 months
Typical At-Power Maintenance Intervals (4)		
• Analog channels	24 months	> 24 months
• Logic cabinets (SSPS)	18 months	> 18 months
• 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	> 12 months

Table 1 (Continued)
WCAP-14333 Implementation Guidelines: Applicability of the Analysis General Parameters to BVPS Units 1 and 2

Parameter	WCAP-14333 Analysis Assumptions	Plant Specific Parameter
ATWS Mitigating System Actuation Circuitry (AMSAC) (6)	Credited for AFW pump start	Credited for AFW pump start
Total Transient Event Frequency (7)	3.6/year	Unit 1: 2.03/year Unit 2: 1.17/year
ATWS Contribution to CDF (current PRA model) (8)	8.4E-06/year	Unit 1: 3.85E-07/year Unit 2: 1.57E-07/year
Total CDF from Internal Events (current PRA model) (9)	5.8E-05/year	Unit 1: 3.98E-06/year Unit 2: 9.53E-06/year
Total CDF from Internal Events (IPE) (10)	Not Applicable	Unit 1: 2.14E-04/year Unit 2: 1.92E-04/year (11)

Notes for Table 1:

1. Both types of logic cabinets, SSPS and Relay, are included in WCAP-14333 and the analysis is applicable to BVPS Units 1 and 2.
2. Since our test intervals are equal to or greater than those used in WCAP-14333, the analysis is applicable to BVPS Units 1 and 2.
3. Since channel calibrations are done at-power and the calibration interval is equal to or greater than that used in WCAP-14333, the analysis is applicable to BVPS Units 1 and 2.
4. Since our maintenance intervals are equal to or greater than those used in WCAP-14333, the analysis is applicable to BVPS Units 1 and 2.
5. Only corrective maintenance is done on the master and slave relays. The typical maintenance interval is relatively long; that is, experience has shown they do not typically completely fail. Failure of these relays usually involves failure of individual contacts. Since "infrequent" master and slave relay failures are the norm, the WCAP-14333 analysis is applicable to BVPS Units 1 and 2.
6. Since AMSAC will initiate AFW pump start, the WCAP-14333 analysis is applicable to BVPS Units 1 and 2.
7. This entry includes the total frequency for initiators requiring a reactor trip signal to be generated for event mitigation to assess the importance of ATWS events to CDF. Since the plant specific value is less than the WCAP-14333 value, this analysis is applicable to BVPS Units 1 and 2.

8. This entry indicates the ATWS contribution to core damage frequency (from at-power, internal events) to determine if the ATWS event is a large contributor to CDF.
9. This entry indicates the total CDF from internal events (including internal flooding) for the most recent PRA model update for comparison to the NRC's risk-informed CDF acceptance guidelines.
10. This entry indicates the total CDF from internal events from the IPE model submitted to the NRC in response to Generic Letter 88-20. See Note 11 for differences between the most recent PRA model update and that included in the GL 88-20 response.
11. Note 10 requires reconciliation between the current CDF and that reported to the NRC in response to GL 88-20. See Sections 3.1.7.1 and 3.1.7.2 of this LAR, which reference FENOC submittals that provide additional information regarding the current PRA model.

Table 2

WCAP-15376 Implementation Guidelines: Applicability of the Analysis General Parameters to BVPS Units 1 and 2

a,c

Table 2 (Continued)

WCAP-15376 Implementation Guidelines: Applicability of the Analysis General Parameters to BVPS Units 1 and 2

a,c

a,c

Table 3
WCAP-14333 and WCAP-15376 Implementation Guidelines:
Applicability of Analysis Reactor Trip Actuation Signals for BVPS Units 1 and 2

a,c

a.c

[ ]

Table 4
WCAP-14333 and WCAP-15376 Implementation Guidelines:
Applicability of Analysis Engineered Safety Features Actuation Signals for BVPS Units 1 and 2

a,c

Table 5

WCAP-15376 Implementation Guidelines:

Applicability of the Human Reliability Analysis for BVPS Units 1 and 2

a,c