WESTINGHOUSE OWNERS GROUP
GUIDELINES FOR PREPARING SUBMITTALS
REQUESTING REVISION OF REACTOR PROTECTION
SYSTEM TECHNICAL SPECIFICATION

1.0 INTRODUCTION

In response to growing concerns of the impact of current testing and maintenance requirements on plant operation, particularly as related to instrumentation systems, the Westinghouse Owners Group (WOG) initiated a program to develop a justification to be used to revise generic and plant specific instrumentation technical specifications. Operating plants experienced many inadvertent reactor trips during performance of instrumentation surveillance, causing unnecessary transients and challenges to safety systems. Significant time and effort on the part of the operating staff was devoted to performing, reviewing, documenting and tracking the various surveillance activities, which in many instances seemed unwarranted based on the high reliability of the equipment. Significant benefits for operating plants appeared to be achievable through revision of instrumentation test and maintenance requirements.

On February 3, 1983 the Westinghouse Owners Group submitted (letter OG-86) WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System" to the NRC as the first step in gaining approval of the instrumentation program. WCAP-10271 documents the justification to be used to justify revisions to technical specifications. The justification consists of the deterministic and numerical evaluation of the effects of particular technical specification changes with consideration given to such things as safety, equipment requirements, human factors and operational impact. The objective is to reach a balance in which safety and operability are ensured. The technical specification revisions evaluated were increased test and maintenance times, less frequent surveillance, and testing in bypass.

In July 1983 the NRC requested additional information from the WOG (letter to J. J. Sheppard from Cecil O. Thomas dated July 28, 1983) required for continued review. The WOG responded in October 1983 (letter OG-106 dated October 4, 1983) with responses to the NRC concerns and Supplement 1 to WCAP-10271 which contains information in addition to that in WCAP-10271. Specifically, Supplement 1 demonstrates the applicability of the justification contained in WCAP-10271 to reactor protection systems for two, three and four loop plants with either relay or solid state logic.

Additionally this supplement extends the evaluation to topics not addressed in the original WCAP such as the interdependence (or lack there of) of surveillance intervals and hardware failure rates.

In February 1985 the NRC issued the SER (letter to J. J. Sheppard from Cecil O. Thomas dated February 21, 1985) for WCAP-10271 and Supplement 1. The SER approve quarterly testing, a 6-hour outage time, increased test time and testing in bypass for analog channels.

At a meeting with Harold Denton on January 9, 1985 convened to discuss the forthcoming SER the Westinghouse Owners Group made a commitment to develop a guidance document to facilitate plant specific technical specification change requests resulting from the approval of WCAP-10271. The NRC strongly encouraged the preparation of this sort of document in the meeting and in their transmittal letter for the safety evaluation of the WCAP (reference 5). The purpose of this guidance document is to ensure consistency in plant specific submittals in order to expedite NRC review.

This guidance document identifies the technical specification changes given generic approval by NRC. It also identifies specific requirements each utility must address to gain NRC approval of their plant specific technical specification changes. A generic significant hazards evaluation has been prepared. The member utilities are encouraged to use this guidance document to ensure that the plant specific submittals are consistent with the changes approved by NRC, to ensure that the NRC requirements are properly addressed, and to ensure proper public notice.

2.0 SIGNIFICANT HAZARDS EVALUATION

Significant Hazards Consideration Analysis - Pursuant to 10CFR50.91 and 10CFR50.92 For The Proposed Amendment to [Name of Plant] Reactor Protection System Instrumentation Technical Specifications

Proposed Changes

Revisions to [Name of Plant] Reactor Protection System (RPS) Instrumentation Technical Specifications are proposed as follows:

1. Increase the surveillance interval for RPS analog channel operational tests from once per month to once per quarter,

2. Increase the time during which an inoperable RPS analog channel may be maintained in an untripped condition from one hour to six hours,

3. Increase the time an inoperable RPS analog channel may be bypassed to allow testing of another channel in the same function from two hours to four hours, and

4. Allow RPS analog channel testing in a bypassed condition instead of a tripped condition.

Analysis

[Name of Utility] has reviewed the requirements of 10CFR50.92 as they relate to the proposed RPS technical specification changes for the [Name of Plant] and determined that a significant hazards consideration is not involved. In support of this conclusion, the following analysis is provided.

Criterion 1 - Operation of [Name of Plant] in accordance with the proposed license amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated.

Implementation of the proposed changes is expected to result in an increase in total Reactor Protection System yearly unavailability of less than 3%. This increase, which is primarily due to less frequent surveillance, results in a increase of similar magnitude (approximately 3%) in the probability of an Anticipated Transient Without Trip (ATWT) and in the probability of core melt resulting from an ATWT. With this slight increase, the probability of ATWT and core melt from ATWT remain within published acceptance criteria.

Implementation of the proposed changes is expected to result in a 30% reduction in the probability of core melt from inadvertent reactor trips. This is a result of a reduction in the number of inadvertent reactor trips (0.5 fewer inadvertent reactor trips per unit per year) occurring during

testing of RPS instrumentation. This reduction is primarily attributable to testing in bypass and less frequent surveillance.

The reduction in inadvertent core melt probability is sufficiently large to counter the increase in ATWT core melt probability resulting in an overall reduction in total core melt probability of approximately 1%.

The proposed changes do not result in an increase in the severity or consequences of an accident previously evaluated. Implementation of the proposed changes affects the probability of failure of the RPS but does not alter the manner in which protection is afforded nor the manner in which limiting criteria are established.

Criterion 2 - The proposed license amendment does not create the possibility of a new or different kind of accident from any accident previously evaluated.

The proposed changes do not result in a change in the manner in which the Reactor Protection System provides plant protection. No change is being made which alters the functioning of the Reactor Protection System (other than in a test mode). Rather, the likelihood or probability of the Reactor Protection System functioning properly is affected as described above. Therefore, the proposed changes do not create the possibility of a new or different kind of accident nor involve a reduction in a margin of safety as defined in the Safety Analysis Report.

The proposed changes do not involve hardware changes except those necessary to implement testing in bypass. Some existing instrumentation is designed to be tested in bypass and current technical specifications allow testing in bypass. Testing in bypass is also recognized by IEEE Standards. Therefore testing in bypass has been previously approved and implementation of the proposed changes for testing in bypass does not create the possibility of a new or different kind of accident from any previously evaluated. Furthermore since the other proposed changes do not alter the functioning of the RPS the possibility of a new or different kind of accident from any previously evaluated has not been created.

Criterion 3 - The proposed license amendment does not involve a significant reduction in a margin of safety.

The proposed changes do not alter the manner in which safety limits, limiting safety system setpoints or limiting conditions for operation are determined. The impact of reduced testing other than as addressed above is to allow a longer time interval over which instrument uncertainties (e.g., drift) may act. Experience at two Westinghouse plants with extended surveillance intervals has shown the initial uncertainty assumptions to be valid for reduced testing.

Implementation of the proposed changes is expected to result in an overall improvement in safety by:

a. 0.5 fewer inadvertent reactor trips per unit. This is due to less frequent testing and testing in bypass which minimizes the time spent in a partial trip condition.

b. Higher quality repairs leading to improved equipment reliability due to longer repair times.

c. Improvements in the effectiveness of the operating staff in monitoring and controlling plant operation. This is due to less frequent distraction of the operator and shift supervisor to attend to instrumentation testing.

Example

10CFR50 - Statements of Consideration contains, "Examples of Amendments that are Considered Not Likely to Involve Significant Hazards Considerations". One of the examples provided is:

> (vi) A change which either may result in some increase to the probability or consequences of a previously-analyzed accident or may reduce in some way a safety margin, but where the results of the change are clearly within all acceptable criteria with respect to the system or component specified in the Standard Review Plan: for

example, a change resulting from the application of a small refinement of a previously used calculational model or design method.

As previously stated implementation of the proposed changes results in a slight increase in the probability of ATWT and ATWT core melt. With this increase the probability of core melt from ATWT remains within published acceptance criteria. Overall core melt probability decreases. Implementation of the proposed changes does not increase the consequences of a previously analyzed accident nor reduce a margin of safety. Functioning of the RPS and the manner in which limiting criteria is established is unaffected. The stated example of a change which is likely not to involve a significant hazards consideration is applicable therefore to the proposed changes.

Conclusion

The foregoing analysis demonstrates that the proposed amendment to [Name of Plant] technical specifications does not involve a significant increase in the probability or consequences of a previously evaluated accident, does not create the possibility of a new or different kind of accident and does not involve a significant reduction in a margin of safety. Additionally fewer inadvertent reactor trips are expected, equipment reliability is expected to increase and operator effectiveness is expected to improve.

Based upon the preceding analysis, [Name of Utility] concludes that the proposed amendment does not involve a significant hazards consideration.

3.0 TECHNICAL SPECIFICATION CHANGES APPROVED

Four specific changes were approved by the Nuclear Regulatory Commission. These changes are limited to the specific RPS channels evaluated in the WCAP and are subject to the specific conditions specified by NRC. The NRC conditions that must be addressed by each utility are addressed elsewhere in this document. No changes to the testing of the actuation logic and reactor trip breakers were approved at this time.

3.1 The surveillance or test frequency may be changed from monthly to quarterly.

3.2 The time allowed for a channel to be inoperable or out of service in an untripped condition may be changed from one hour to six hours.

3.3 The time a channel in a functional group may be bypassed to perform testing may be increased from two to four hours. This bypass time applies to either an inoperable channel when testing is done in the tripped mode or to the channel in test when testing is done in the bypass mode.

3.4 Routine channel testing may be performed in the bypassed condition instead of the tripped condition.

Appendix A of this document provides proposed technical specifications which implement the approved revisions described above and in the SER. Additionally, proposed revisions which address the contingencies contained in the SER are included. NUREG-0452 Rev. 4 was used in developing the proposed technical specifications. However, WCAP-10271 and Supplement 1 and the SER are applicable to all Westinghouse plants regardless of the type or revision of technical specification used. The proposed technical specifications contained in this document are to be used as an example in preparing plant specific submittals. It is expected that proposed changes to plant technical specifications contained in plant specific submittals will vary in content from the specifications contained in this document though incorporating the principle of the proposed specifications.

The RPS functions which were evaluated in WCAP-10271 and Supplement 1 and to which the SER is applicable are listed below. Technical specification revisions may be requested for those functions using the technical specification format in use at the respective plant.

<u>Protective Function</u>

1. High Flux Power Range, H[illegible]point
2. High Flux Power Range, Lo[illegible]int
3. High Negative Flux Rate
4. High Positive Flux Rate
5. High Flux Intermediate Range

6. High Flux Source Range
7. Overtemperature Delta-T
8. Overpower Delta-T
9. Pressurizer Pressure, Low
10. Pressurizer Pressure, High
11. Pressurizer Water Level, High
12. Loss of Flow, Single Loop
13. Loss of Flow, Two Loop
14. Steam Generator Water Level, Low-Low
15. Steam Flow/Feed Flow Mismatch With Low Steam Generator Level
16. RCP Bus Undervoltage
17. RCP Bus Underfrequency
18. RCP Underspeed, Low
19. RCP Underspeed, Low-Low
20. Turbine Trip

4.0 NRC IMPOSED CONDITIONS

The NRC has imposed five conditions on utilities seeking to implement the technical specification changes approved generically as a result of their review of WCAP-10271. These conditions must be addressed by each utility in the plant specific technical specification change request. A Westinghouse Owners Group position is provided for each condition.

4.1 The first condition requires the use of a staggered test plan for the RPS channels changed to the quarterly test frequency. As stated by NRC in the safety evaluation for WCAP-10271:

> System unavailability, or probability of failure due to common cause, is proportional to the time between staggered tests. Therefore, if the test interval is expanded, the failur probability will increase. A staggered plan which "spreads" the channel testing over the quarter rather than "concentrating" the channel testing would reduce the potential for common cause function failure and at the same time still accomplish the goals set forth by the Owners Group. Accordingly, the staff's acceptance of less frequent surveillance is contingent on the implementation of a staggered test plan.

The WOG recommends that each utility implement a staggered test plan at the time quarterly testing goes into effect to satisfy the NRC condition of acceptance contained in the SER. For example, under this plan one channel of a four channel function must be tested every three weeks such that all channels are tested each quarter. One channel of a three channel function must be tested every month. One channel of a two channel function must be tested every six weeks.

The Westinghouse Owners Group recommends that the staggered testing requirement be made part of the technical specification change. This can be accomplished by the addition of a new note to the surveillance schedule table using the standard technical specification definition for STAGGERED TEST BASIS. The surveillance table would then be modified to reference the footnote wherever quarterly testing is specified. Optionally each utility may choose to administratively control staggered testing by appropriate changes to test procedures, test schedules, etc. rather than implement technical specification changes.

Revised pages from the Westinghouse standard technical specifications are included in the Appendix to illustrate these changes.

4.2 The second condition requires that plant procedures require a common mode evaluation for failure in the RPS channels changed to the quarterly test frequency and additional testing for plausible common cause failures. As stated by NRC in the safety evaluation for WCAP-10271:

> The staff's evaluation of RPS unavailability assumed that common cause failures would be identified during testing. The staff's assumption was that the identification would occur because all the additional channels in a function would be tested whenever one channel failed a test. However, from a practical standpoint, there are several kinds of failures which the staff does not regard as common cause failures, e.g., instrument drift and failure of power to a single channel. Additional testing is not necessary for these failures or other failures if the cause of

those other failures can be evaluated and shown not to affect multiple channels. In order to validate the staff's underlying assumption, the staff's acceptance of less frequent surveillance is contingent on implementation of procedures to identify common cause failures and to test the other channels which may be affected by the common cause.

The Westinghouse Owners Group recommends that each utility implement or confirm the existence of procedures which require the evaluation of a failure of any RPS channel on the quarterly test program to determine if that failure could be a common cause failure, to satisfy the NRC condition of acceptance contained in the SER. The plant procedure should require that the appropriate remedial action, such as additional testing of the other channels in that function, occur if the failure is determined to be a plausible common cause failure. As noted above, failures such as instrument drift and power supply failures to a single channel are not considered common cause failures. Additional testing is not required for these types of failures. Additionally, failures of the sort that are "announced" through control room alarms or annunciation or through other readily observed means need not be considered to be plausible common cause problems and do not require additional testing. Any additional testing that is performed should be consistent with the types of problems to be found. For example, if the failure cannot be detected by standard channel tests, testing other than the standard channel test should be performed.

In making a determination about common cause, the utility may consider the nature of the failure, the experience of their equipment, and industry experience in general. For example, a transistor failure may be considered a plausible common mode failure because that type of transistor is used in other circuits. However, a utility may conclude that it is not a plausible common mode failure if similar failures in their equipment have been rare and no significant problems have been identified through the utility's industry experience review program.

Plausible common cause problems should be identified only where failure can be shown to be attributable to processes which are common

to redundant equipment. That is, the underlying failure mechanism must be shown to have had the potential for causing failures in redundant channels. Failures and/or failure mechanisms which do not satisfy this criteria should not be considered as a plausible common cause problem. Some examples of plausible common cause problems are presented. A simple transistor failure that has no distinguishing characteristics may be considered a random failure. However, if the failure is attributed to a temperature excursion in the rack cabinet, it may be considered a plausible common cause problem. In this case testing of the circuits affected by the temperature excursion may be warranted. The failure may also be considered a plausible common cause problem if the failure was attributed to an improper test method that damaged components and that damage can only be found by subsequent testing. In this case a review of the test records may indicate other channels subjected to the improper test method that warrant additional testing.

It is the position of the Westinghouse Owners Group that the intent of this condition is not to judge every failure as a potential common cause problem. Equipment is expected to fail. Rather, the intent is to make the utility conscious of common mode problems and to take additional action when a plausible common mode problem is identified. This condition need not require supplemental experience review when a channel problem is identified. The normal industry experience review programs currently in place are sufficient to identify problems that may contain elements of common cause.

Each utility request for amendment must contain a confirmation of the existence of a program or procedures which address the identification of and required actions associated with plausible common cause problems. The program and/or procedures need not be submitted to the NRC.

4.3 The third condition requires installed hardware capability for testing in the bypass mode. As stated by NRC in the safety evaluation for WCAP-10271:

Testing of the RPS analog channels in the bypassed condition by use of temporary jumpers or by lifting leads is not acceptable. The chance of personnel errors leaving a number of channels in the bypassed condition would be too large for the routine use of such methods. Therefore, licensees choosing this option to perform routine channel testing in the bypass mode should ensure that the plant design allows testing in bypass without lifting leads or installing temporary jumpers. The staff's acceptance of this option is contingent on confirmation of this capability.

To satisfy the conditions of acceptance contained in the SER the Westinghouse Owners Group recommends that each utility commit to test in bypass only after any hardware changes necessary (if any) to allow testing in bypass without reliance on lifted leads or jumpers (other than those necessary to connect test equipment) are implemented. The Westinghouse Owners Group recommends utilities with plants that currently have bypass capability, to test in bypass and to request appropriate technical specification revisions to allow testing in bypass. Utilities which have plants which do not have bypass capability or which have bypass capability for only a portion of RPS channels may defer submittal of this portion of the optimization package until such time as the capability to test in bypass is installed or optionally, request technical specification revisions at this time as discussed in the following paragraph. Deferment of this portion in no way precludes submittal of any or all other portions of the optimization package. Each utility should reference any such future plans in any submittals made now. All such future submittals should be made in accordance with the guidelines contained in this document to facilitate NRC review.

Proposed technical specifications are contained in Appendix A of this document. Referring to Appendix A, specifically part b of Actions 2 and 6, the following should be noted:

1. The action for channels without bypass capability which allows testing of additional channels with one channel inoperable can be used for channels with bypass capability. However, compliance with this action requires the inoperable channel to be taken out

of trip and placed in bypass. The operable channel to be tested would be tested in the tripped mode. Following testing the tested channel would be restored to normal operation and the inoperable channel returned to the tripped condition. During the flip-flopping of channels from trip to bypass, etc. a potential exists for two channels to be inadvertently placed in trip. For this reason it is recommended that this action not be used for channels with bypass capability.

2. The action for channels with bypass capability which allows testing of additional channels with one channel inoperable cannot be used for channels without bypass capability. Channels without bypass capability cannot be tested without actuating the associated bistable. Actuation of the bistable of the channel being tested would in conjunction with the tripped inoperable channel resul. in a reactor trip.

It is acceptable to include both actions into the technical specification. This allows for some channels to be tested in trip and some in bypass and allows a transition to occur from testing in trip to testing in bypass without additional technical specification changes. In other words technical specification changes could be made in advance of the hardware changes. No technical specification changes would be required when the hardware changes were made. Optionally each utility may choose one action as the hardware situation dictates and revise the technical specifications as the hardware is revised.

Utilities need not include detailed descriptions or discussions of hardware changes in individual plant submittals. Rather, the Westinghouse Owners Group recommends that each utility commit to design and install any and all hardware changes necessary to allow testing in bypass in accordance with the existing licensing basis and to review the hardware changes in accordance with 10CFR50.59. NRC notification of hardware changes would be made in accordance with the 10CFR50.59 review conducted. It is recommended that each utility submittal list the RPS functions with installed bypass capability or for which the utility intends to install bypass capability. The NRC

safety evaluation granting approval of the capability to test in bypass is not limited to any particular logic configuration. The Westinghouse Owners Group considers test in bypass to be applicable to all logic combinations for the channels listed in WCAP-10271 Supplement 1.

4.4 The fourth condition involves channels that provide input to both the RPS and the engineered safety feature actuation system (ESFAS). As stated by NRC in the safety evaluation for WCAP-10271:

> In order to avoid confusion in plant technical specifications regarding such dual function channels, the staff concludes that either (1) the channels should not be changed in the RPS tables until the ESFAS review is finished or (2) cautionary notes in the RPS tables should refer to the more stringent ESFAS requirements.

Each utility must decide how they want to control the difference in requirements between the RPS and ESFAS. The Westinghouse Owners Group recommends that the proposed changes to the RPS technical specifications be made for all evaluated channels and that appropriate cautionary statements be added to the action statements referencing the more stringent requirements for the ESFAS channels. It is recommended that administrative controls be established to ensure that the more restrictive requirements are observed. For the utilities that choose not to change the RPS part of the dual function channels, the changes to the channels that are strictly RPS may be pursued independently of the future ESFAS work.

For those channels which have both RPS and ESFAS functions all failures and testing will either involve parts of the channel that are common to both the ESFAS and RPS function or they will be limited to one or the other. Testing and failures in the common part of the channels must follow the more restrictive technical specification requirements for the ESFAS equipment. Testing and failures that are limited to the RPS portion of the channel may follow the relaxed requirements. For example, a failure of a RPS bistable card would be subject to the relaxed RPS portion of the system. On the other hand, a failure of the transmitter that provides a signal to both RPS and

ESFAS bistables would be subject to the more restrictive ESFAS action time. Also, in cases where a separate bistable card is used for RPS and ESFAS setpoints, the RPS card may be tested on the relaxed RPS schedule.

An example of proposed Westinghouse standard technical specifications to address the cautionary notes is included in the Appendix. Concerning the proposed technical specifications, specifically the cautionary notes and the affected channels or surveillance requirements, the following should be noted:

1. The channels noted as requiring special attention due to differences in outage times and surveillance intervals are typical. Each utility should determine those channels which have dual function on a plant specific bases and make revisions accordingly.

2. The cautionary notes do not change existing technical specification requirements. That is, the requirements to test ESF channels monthly and to place inoperable ESF channels in trip within one hour remain limiting with respect to RPS channels with dual function regardless of the cautionary note. The cautionary note is for clarification purposes only. It serves as a reminder to diminish the possibility of an unintentional technical specification violation.

3. The cautionary note is applicable to the conditions in which RPS requirements are less restrictive than ESF requirements and to the condition in which RPS and ESF requirements are identical. In this regard the cautionary note may be retained in the technical specifications or it may be deleted, as the utility prefers, upon implementation of similar revision to ESF instrumentation requirements.

4.5 The fifth condition addresses setpoint drift. As stated by NRC in the safety evaluation for WCAP-10271:

Based on review of previous Westinghouse topical reports, the staff notes that margin is included in the channel setpoint determination to account for possible instrument drift over a one month surveillance interval. Accordingly, the staff's acceptance is contingent on confirmation that the instrument setpoint methodology includes sufficient adjustments to offset the drift anticipated as a result of less frequent surveillance.

The setpoint methodology allowance for drift is chosen to conservatively bound any anticipated drift over a one month surveillance interval. The Westinghouse Owners Group does not have sufficient data to conclude that the setpoint allowance also conservatively bounds any anticipated drift over a quarterly surveillance interval. Each utility will have to address this condition and should choose one of two options to address instrument setpoint drift. One choice is to review plant specific instrument calibration records for these channels to determine equipment performance. The bistable equipment is inherently stable and should show good performance. In many cases, channels are not recalibrated for many months. A review of the "as found" and "as left" data over a twelve month period should provide sufficient information to address the adequacy of the existing setpoints and allowable values. The second choice is to make a commitment to collect the "as found" and "as left" data for each channel over a one year period after quarterly testing has begun and to make any necessary changes to the setpoints and allowable values, as necessary, after the data has been reviewed.

5.0 JUSTIFICATION FOR TECHNICAL SPECIFICATION CHANGES

To facilitate NRC review of submittals the Westinghouse Owners Group recommends that each utility reference WCAP-10271-A and Supplement 1 and the NRC safety evaluation for WCAP-10271 as justification for their plant specific technical specifications. The WCAP safety evaluation and the utility specific responses to the five conditions identified above are all that is required to support these technical specification changes.

6.0 REFERENCES

6.0 REFERENCES

6.1 WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System", January 1983.

6.2 WCAP-10271 Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System", July 1983.

6.3 Letter (OG-86) from J. J. Sheppard (WOG - CP&L) to H. R. Denton (NRC) dated February 3, 1983 (WCAP-10271 submittal).

6.4 Letter from C. O. Thomas (NRC) to J. J. Sheppard (WOG - CP&L) dated July 28, 1983 (NRC Request Number 1 for Additional Information on WCAP-10271).

6.5 Letter (OG-106) from J. J. Sheppard (WOG - CP&L) to C. O. Thomas (NRC) dated October 4, 1983 (WCAP-10271 Supplement 1 and question response submittal).

6.6 Letter from C. O. Thomas (NRC) to J. J. Sheppard (WOG - CP&L) dated February 21, 1985 (NRC safety evaluation for WCAP-10271).

APPENDIX A

PROPOSED CHANGES TO STANDARD TECHNICAL SPECIFIC\TIONS

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR TRIP SYSTEM INSTRUMENTATION

LIMITING C(:TION FOR OPERATION

3.3.1 As a minimum, the reactor trip system instrumentation channels and interlocks of Table 3.3-1 shall be OPERABLE with REPONSE TIMES as shown in Table 3.3-2.

APPLICABILITY: As shown in Table 3.3-1

ACTION: As shown in Table 3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor trip system instrumentation channel and interlock and the automatic trip logic shall be demonstrated OPERABLE by the performance of the reactor trip system instrumentation surveillance requi· ·ents specified in Table 4.3-1.

4.3.1.2 The REACTOR TRIP SYSTEM RESPONSE TIME of each reactor trip function shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least one train such that both trains are test at least once per 36 months and one channel per function such t' . all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip function as shown in the "Total No. · Channels" column of Table 3.3-1.

TABLE 3.3-1

REACTOR TRIP SYSTEM INSTRUMENTATI

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2	1	2	1, 2	1
	2	1	2	3*, 4*, 5*	13
2. Power Range, Neutron Flux - High Setpoint	4	2	3	1, 2	2#
Low Setpoint	4	2	3	1###, 2	2#
3. Power Range, Neutron Flux High Positive Rate	4	2	3	1, 2	2#
4. Power Range, Neutron Flux, High Negative Rate	4	2	3	1, 2	2#
5. Intermediate Range, Neutron Flux	2	1	2	1###, 2	3
6. Source Range, Neutron Flux					
A. Startup	2	1	2	2##	4
B. Shutdown	2	1	2	3*, 4*, 5*	13
C. Shutdown	2	0	1	3, 4, and 5	5
7. Overtemperature ΔT					
A. Four Loop Plant					
Four Loop Operation	4	2	3	1, 2	6#
Three Loop Operation	4	1**	3	1, 2	9
B. Three Loop Plant					
Three Loop Operation	3	2	2	1, 2	6#
Two Loop Operation	3	1**	2	1, 2	9

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
8. Overpower ΔT					
A. Four Loop Plant					
Four Loop Operation	4	2	3	1, 2	6#
Three Loop Operation	4	1**	3	1, 2	9
B. Three Loop Plant					
Three Loop Operation	3	2	2	1, 2	6#
Two Loop Operation	3	1**	2	1, 2	9
9. Pressurizer Pressure--Low					
A. Four Loop Plant	4	2	3	1	6#,***
B. Three Loop Plant	3	2	2	1	6#,***
10. Pressurizer Pressure--High					
A. Four Loop Plant	4	2	3	1, 2	6#,***
B. Three Loop Plant	3	2	2	1, 2	6#,***
11. Pressurizer Water Level--High	3	2	2	1	6#
12. Loss of Flow					
A. Single Loop (Above P-8)	3/loop	2/loop in any operating loop	2/loop in each operating loop	1	6#
B. Two Loops (Above P-7 and below P-8)	3/loop	2/loop in two operating loops	2/loop in each operating loop	1	6#

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
13. Steam Generator Water Level--Low-Low	3/stm. gen.	2/stm. gen. in any operating stm. gen.	2/stm. gen. each operating stm. gen.	1, 2	6#,***
14. Steam Generator Water Level - Low Coincident With Steam/ Feedwater Flow Mismatch	2 stm. gen. level and 2 stm/feed-flow mismatch in each stm. gen.	1 stm. gen. level coincident with 1 stm/feed-flow mismatch in same stm. gen.	1 stm. gen. level and 2 stm/feed-flow mismatch in same stm. gen. or 2 stm. gen. level and 1 stm/feedflow mismatch in same steam gen.	1, 2	6#,***
15. Undervoltage-Reactor Coolant Pumps					
A. Four Loop Plant	4-1/bus	2	3	1	6#,***
B. Three Loop Plant	3-1/bus	2	2	1	6#,***
16. Underfrequency-Reactor Coolant Pumps					
A. Four Loop Plan	4-1/bus	2	3	1	6#
B. Three Loop Plant	3-1/bus	2	2	1	6#
17. Turbine Trip					
A. Low Fluid Oil Pressure	3	2	2	1	6#
B. Turbine Stop Valve Closure	4	4	4	1	6#
18. Safety Injection Input from ESF	2	1	2	1, 2	12

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
19. Reactor Coolant Pump Breaker Position Trip					
A. Above P-8	1/breaker	1	1/breaker	1	10
B. Above P-7 and below P-8	1/breaker	2	1/breaker per operating loop	1	11
20. Reactor Trip System Interlocks					
A. Intermediate Range Neutron Flux, P-6	2	1	2	2##	8
B. Low Power Reactor Trips Block, P-7					
P-10 Input	4	2	3	1	8
or					
P-13 Input	2	1	2	1	8
C. Power Range Neutron Flux, P-8	4	2	3	1	8
D. Low Setpoint Power Range Neutron Flux, P-10	4	2	3	1, 2	8
E. Turbine Impulse Chamber Pressure, P-13	2	1	2	1	8
21. Reactor Trip Breakers	2	1	2	1, 2	12
	2	1	2	3*, 4*, 5*	13
22. Automatic Trip Logic	2	1	2	1, 2	12
	2	1	2	3*, 4*, 5*	13

Table 3.3-1 (Continued)

TABLE NOTATION

* With the reactor trip system breakers in the closed position, the control rod drive system capable of rod withdrawal.

** The channel(s) associated with the protective functions derived from the out of service Reactor Coolant Loop shall be placed in the tripped condition.

*** Comply with the provisions of Specification 3.3.2, for any portion of the channel required to be OPERABLE by Specification 3.3.2.

\# The provisions of Specification 3.0.4 are not applicable.

\## Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

\### Below the P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

ACTION STATEMENTS

ACTION 1 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours.

ACTION 2 - With the number of OPERABLE Channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b.1 For Channels With Bypass Capability one additional channel may be bypassed for up to 4 hours for surveillance testing

per Specification 4.3.1.1 provided the inoperable channel is in the tripped condition.

b.2 For Channels With No Bypass Capability the Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.

c. Either, THERMAL POWER is restricted to less than or equal to 75 percent of RATED THERMAL POWER and the Power Range Neutron Flux trip setpoint is reduced to less than or equal to (85 percent) of RATED THERMAL POWER within 4 hours; or, the QUADRANT POWER TILT RATIO is monitored at least once per 12 hours per Specification 4.2.4.2.

ACTION 3 - With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below the P-6 (Intermediate Range Neutron Flux Interlock) setpoint, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint.

b. Above the P-6 (Intermediate Range Neutron Flux Interlock) setpoint but below 10 percent of RATED THERMAL POWER, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above 10 percent of RATED THERMAL POWER.

ACTION 4 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement suspend all operations involving positive reactivity changes.

ACTION 5 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, verify compliance with the SHUTDOWN MARGIN requirements of Specification 3.1.1.1 or 3.1.1.2, as applicable, within 1 hour and at least once per 12 hours thereafter.

TABLE 3.3-1 (Continued)
ACTION STATEMENTS (Continued)

ACTION 6 - With the number of OPERABLE Channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b.1 For Channels With Bypass Capability one additional channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.1.1 provided the inoperable channel is in the tripped condition.

b.2 For Channels With No Bypass Capability the Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.

ACTION 7 - Delete.

ACTION 8 - With less than the Minimum Number of Channels OPERABLE, within one hour determine by observation of the associated permissive annunciator window(s) that the interlock is in its required state for the existing plant condition, or apply Specification 3.0.3.

ACTION 9 - With a channel associated with an operating loop inoperable, restore the inoperable channel to OPERABLE status within 6 hours or be in at least HOT STANDBY within the next 6 hours. One channel associated with an operating loop may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.1.1.

ACTION 10 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 6 hours or reduce THERMAL POWER to below the P-8 (Power Range Neutron Flux Interlock) setpoint within the next 2 hours. Operation below the P-8 setpoint may continued pursuant to ACTION 11.

TABLE 3.3-1 (Continued)
ACTION STATEMENTS (Continued)

ACTION 11 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, operation may continue provided the inoperable channel is placed in the tripped condition within 6 hours.

ACTION 12 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.1.1, provided the other channel is OPERABLE.

ACTION 13 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the reactor trip breakers within the next hour.

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	N.A.	R	N.A.	1, 2, 3*, 4*, 5*
2. Power Range, Neutron Flux						
High Setpoint	S	D(2, 4) M(3, 4) Q(4, 6) R(4, 5)	Q(11)	N.A.	N.A.	1, 2
Low Setpoint	S	R(4)	Q(11)	N.A.	N.A.	1***, 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	R(4)	Q(11)	N.A.	N.A.	1, 2
4. Power Range, Neutron Flux, High Negative Rate	N.A.	R(4)	Q(11)	N.A.	N.A.	1, 2
5. Intermediate Range, Neutron Flux	S	R(4, 5)	Q(11)	N.A.	N.A.	1***, 2
6. Source Range, Neutron Flux	S	R(4, 5)	Q(9,11)	N.A.	N.A.	2**, 3, 4, 5
7. Overtemperature ΔT	S	R	Q(11)	N.A.	N.A.	1, 2
8. Overpower ΔT	S	R	Q(11)	N.A.	N.A.	1, 2
9. Pressurizer Pressure--Low	S	R	Q(11,12)	N.A.	N.A.	1

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
10. Pressurizer Pressure-High	S	R	Q(11,12)	N.A.	N.A.	1, 2
11. Pressurizer Water Level--High	S	R	Q(11)	N.A.	N.A.	1
12. Loss of Flow	S	R	Q(11)	N.A.	N.A.	1
13. Steam Generator Water Level--Low-Low	S	R	Q(11,12)	N.A.	N.A.	1, 2
14. Steam Generator Water Level--Low Coincident With Steam/Feedwater Flow Mismatch	S	R	Q(11,12)	N.A.	N.A.	1, 2
15. Undervoltage - Reactor Coolant Pumps	N.A.	R	N.A.	Q(11,12)	N.A.	1
16. Underfrequency - Reactor Coolant Pumps	N.A.	R	N.A.	Q(11)	N.A.	1
17. Turbine Trip						
A. Low Fluid Oil Pressure	N.A.	N.A.	N.A.	S/U(1, 10)	N.A.	1
B. Turbine Stop Valve Closure	N.A.	N.A.	N.A.	S/U(1, 10)	N.A.	1
18. Safety Injection Input From ESF	N.A.	N.A.	N.A.	R	N.A.	1, 2

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
19. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	N.A.	R	N.A.	1
20. Reactor Trip System Interlocks						
A. Intermediate Range Neutron Flux, P-6	N.A.	R(4)	Q(11)	N.A.	N.A.	2**
B. Low Power Reactor Trips Block, P-7	N.A.	R(4)	Q(8,11)	N.A.	N.A.	1
C. Power Range Neutron Flux, P-8	N.A.	R(4)	Q(8,11)	N.A.	N.A.	1
D. Low Setpoint Power Range Neutron Flux, P-10	N.A.	R(4)	Q(8,11)	N.A.	N.A.	1, 2
E. Turbine Impulse Chamber Pressure, P-13	N.A.	R	Q(11)	N.A.	N.A.	1
21. Reactor Trip Breaker	N.A.	N.A.	N.A.	M(7)	N.A.	1, 2, 3*, 4*, 5*
22. Automatic Trip Logic	N.A.	N.A.	N.A.	N.A.	M(7)	1, 2, 3*, 4*, 5*

TABLE 4.3-1 (Continued)

TABLE NOTATION

* - With the reactor trip system breakers closed and the control rod drive system capable of rod withdrawal.

** - Below P-6 (Intermediate Range Neutron Flux Interlock) setpoint.

*** - Below P-10 (Low Setpoint Power Range Neutron Flux Interlock) setpoint.

(1) - If not performed in previous 92 days.

(2) - Heat balance only, above 15 percent of RATED THERMAL POWER. Adjust channel if absolute difference greater than 2 percent.

(3) - Compare incore to excore axial flux difference above 15 percent of RATED THERMAL POWER. Recalibrate if the absolute difference is greater than or equal to (3) percent.

(4) - Neutron detectors may be excluded from CHANNEL CALIBRATION.

(5) - Detector plateau curves shall be obtained and evaluated. For the Intermediate Range and Power Range Neutron Flux Channels the provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(6) - Incore - Excore Calibration.

(7) - Each train shall be tested at least every 62 days on a STAGGERED TEST BASIS.

TABLE 4.3-1 (Continued)

TABLE NOTATION

(8) - With power greater than or equal to the interlock setpoint the required OPERATIONAL TEST shall consist of verifying that the interlock is in the required state by observing the permissive annunciator window.

(9) - Quarterly Surveillance in MODES 3*, 4* and 5* shall also include verification that permissives P-6 and P-10 are in their required state for existing plant conditions by observation of the permissive annunciator window.

(10) - Setpoint verification is not applicable.

(11) - Each channel shall be tested at least every 92 days on a STAGGERED TEST BASIS.

(12) - Comply with the surveillance requirements of Specification 4.3.2.1 for any portion of the channel required to be OPERABLE by Specification 3.3.2.

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 and 3/4.3.2 REACTOR TRIP AND ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

The OPERABILITY of the Reactor Protection System and Engineered Safety Feature Actuation System instrumentation and interlocks ensure that 1) the associated action and/or reactor trip will be initiated when the parameter monitored by each channel or combination thereof reaches its setpoint, 2) the specified coincidence logic and sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance consistent with maintaining an appropriate level of reliability of the Reactor Protection and Engineered Safety Features instrumentation and, 3) sufficient system functions capability is availab[illegible] from diverse parameters.

The OPERAB[illegible] of these systems [illegible]equired to provide the overall reliability, redundancy, and diversit[illegible] [illegible]ssumed available in the facility design for the protection of each of these systems is consistent with the assumptions used in the accident analyses. The surveillance requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance tests performed at the minimum frequencies are sufficient to demonstrate this capability. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System", and supplements to that report. Surveillance intervals and out of service times were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation.

The measurement of response time at the specified frequencies provides assurance that the reactor trip and the engineered safety feature actuation associated with each channel is completed within the time limit assumed in the accident analyses. No credit was taken in the analyses for those channels with response times indicated as not applicable. Response time may be demonstrated by a series of sequential, overlapping or total channel response time as defined. Sensor response time verification may be demonstrated by either 1) in place, onsite, or offsite test measurements or, 2) utilizing replacement sensors with certified response times.

The Engineered Safety Feature Actuation System senses selected plant parameters and determines whether or nor predetermined limits are being exceeded. If they are, the signals are combined into logic matrices sensitive to combinations indicative of various accidents, events, and transients. Once the required logic combination is completed, the system sends actuation signals to those engineered safety features components whose aggregate function best serves the requirements of the condition. As an example, the following actions may be initiated by the Engineered Safety Features Actuation System to mitigate the consequences of a steamline break or loss of coolant accident 1) safety injection pumps start and automatic valves position, 2) reactor trip, 3) feedwater isolation, 4) startup of the emergency diesel generators, 5) containment spray pumps start and automatic valves position, 6) containment isolation, 7) steamline isolation, 8) turbine trip, 9) auxiliary feedwater pumps start and automatic valves position, 10) containment cooling fans start and automatic valves position, 11) essential service water pumps start and automatic valves position, 12) control room isolation and ventilation systems start).