UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

NOV 23 1990

MEMORANDUM FOR: Warren Minners, Director, Division of Safety Issue Resolution, Office of Nuclear Regulatory Research

FROM: Eric S. Beckjord, Director, Office of Nuclear Regulatory Research

SUBJECT: GENERIC ISSUE NO. 120, "ON-LINE TESTABILITY OF PROTECTION SYSTEMS"

The prioritization of Generic Issue No. 120, "On-Line Testability of Protection Systems," has resulted in a MEDIUM priority ranking. This memorandum approves DSIR taking the appropriate actions to resolve the issue. The evaluation of the subject issue is provided in Enclosure 1.

In accordance with RES Office Letter No. 1, "Procedure for Identification, Prioritization, and Tracking of the Resolution of Generic Issues," the resolution of this issue will be monitored by the Generic Issue Management Control System (GIMCS). The information needed for this system is indicated on the enclosed GIMCS information sheet (Enclosure 2). Your schedule for resolving this generic issue should be commensurate with the priority nature of the work. As stated in the Office Letter, the information needed should be provided within 6 weeks.

The enclosed prioritization evaluation will be incorporated into NUREG-0933, "A Prioritization of Generic Safety Issues," and is being sent to the regions, other offices, the ACRS, and the PDR, by copy of this memorandum, to allow others the opportunity to comment on the evaluation. Any changes as a result of comments will be coordinated with you. However, the schedule for the resolution of this issue should not be delayed to wait for these comments. The information requested should be sent to the Advanced Reactors and Generic Issues Branch, DRA, RES (Mail Stop NL/S-169). Should you have any questions pertaining to the contents of this memorandum, please contact Ronald Emrit (492-3731).

Eric S. Beckjord
Eric S. Beckjord, Director
Office of Nuclear Regulatory Research

Enclosures:
1. Prioritization Evaluation
2. GIMCS Information Sheet

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ENCLOSURE 1

<u>PRIORITIZATION EVALUATION</u>

Issue 120: On-Line Testability of
Protection Systems

ISSUE 120: ON-LINE TESTABILITY OF PROTECTION SYSTEMS

DESCRIPTION

Historical Background

This issue was raised[1271] by the staff in 1985 during the review of several plant Technical Specifications when it was found that the protection system designs of some older plants did not provide as complete a degree of on-line protection system surveillance testing capability as other plants undergoing staff review and evaluation at that time.

The requirements for at-power testability of components are included in GDC 21 of Appendix A to 10 CFR 50. Supplementary guidance is provided in Regulatory Guides 1.22 and 1.118 and IEEE Standard 338 to ensure that protection systems (including logic, actuation devices, and associated actuated equipment) will be designed to permit testing while a plant is operating without adversely affecting the plant's operation. These requirements apply to both the Reactor Protection System (RPS) and the Emergency Safety Features Actuation System (ESFAS). Current Standard Technical Specifications indicate that it is desirable to test all protection systems through their sub-group relays every 6 months.

Safety Significance

This issue centers upon the risk posed by those plants with lesser degrees of on-line testing capability and the value/impact effects of requiring modifications of the protection systems to allow for a greater degree of on-line testing. On-line testing increases the ability to detect existing failures of the protection system and could therefore result in improved reliability of the system; hence, a reduction in plant risk. In some older plants, a larger portion of the protection system hardware can only be tested through the sub-group relays during plant outages (i.e., shutdowns) which typically have an 18-month frequency. Therefore, modification of the protection system to allow for semiannual testing through the sub-group relays could result in risk reduction at those plants.

Possible Solution

The following two options are identified as potential solutions:

(1) Recognize that there are cases where there are no practical system design modifications that will permit at-power operation of the actuated equipment without adversely affecting the safety or operability of a plant. Exceptions could be taken that include not testing the automatic initiating logic and associated actuating devices. Actions could include: (1) submittal of information by licensees to describe and justify any deviations from regulatory requirements and to describe the revision of the plant technical specifications stating the testing required; and (2) testing of those systems that can be tested without defeating the ESFAS train or RPS.

(2) Design and implement modifications to allow compliance with the requirements for on-line testing of all systems without defeating the ESFAS train or RPS. Each channel of the reactor trip module (RTM) needs to be provided with two key-operated bypass switches, a channel bypass switch, and a shutdown bypass switch. The 2/4 system would then operate in the 2/3 mode during the testing.

It is believed that changing the testing frequency of the protection system components to 6-month intervals, instead of the current 18-month intervals, will increase the reliability of these components and result in an overall enhancement of plant safety.

PRIORITY DETERMINATION

Frequency Estimate

For the purpose of this analysis, it was assumed that modifications would be made to allow for an increase in test frequency to 6 months (from 18 months) for 20% of the relays in the RPS. In this analysis, changes in the test frequency for ESFAS relays were not considered because they could not be as readily incorporated into the representative plant PRAs.

The Oconee 3 and Grand Gulf 1 PRAs were used as the representative PWR and BWR, respectively, to estimate the change in the reliability of RPS components due to revised testing frequency (from the current 18-month testing interval to 6-month interval) and the resultant change in the core-melt frequency.[64] Thus, the changes in core-melt frequency were estimated based on reductions in failure rates for relays in the RPS that would result from licensee implementation of potential solutions. It was assumed that the values in the Oconee 3 and Grand Gulf 1 PRAs were based on the 6-month test interval for all relays in the RPS and that these plants are in full compliance with on-line testing requirements. These values were then considered to be adjusted case values for the purposes of this analysis. Therefore, the base case represents the situation in which only a fraction of the relays can be tested during refueling outages or other extended shutdowns (an 18-month test interval for these relays is assumed).

The affected parameter in the Oconee 3 PRA is considered to be K, failure of RPS due primarily to test and maintenance faults (frequency of 2.6×10^{-5}/demand). The affected parameter for Grand Gulf 1 is considered to be C, failure to render the reactor subcritical (frequency of 7.7×10^{-7}/demand). These K and C estimates are then assumed to represent the adjusted case values. To calculate the base case values for a change in test frequency from 6 to 18 months, relay unavailability data from ANO-2 for the two testing frequencies were used. In addition, it was also assumed that the testing of all 100 relays, instead of the approximately 80 relays that are currently being tested, will increase the unavailability of 1 of 4 RTMs by 25%. The ANO-2 relay unavailability data for the 6-month and 18-month testing intervals are 7.2×10^{-4}/demand and 2.2×10^{-3}/demand, respectively.[1272] By using these values in the RPS fault tree given in NUREG/CR-2800,[64] base case values of 2.96×10^{-5}/demand and 9.2×10^{-7}/demand for K and C, respectively, were calculated.

Note that these are the values relating to the 18-month testing intervals. Substituting these values for the affected parameters in the Oconee 3 and Grand Gulf 1 PRAs results in core-melt frequency reductions of 1.2×10^{-6}/RY and 10^{-6}/RY for a PWR and BWR, respectively. The generic release categories and containment failure modes associated with this issue are as follows:[64]

Release Category	Containment Failure Mode Probability	Whole Body Dose (man-rem)
PWR-3	0.5	5.4×10^{6}
PWR-5	0.0073	1.0×10^{6}
PWR-7	0.5	2.3×10^{3}
BWR-2	1.0	7.1×10^{6}

Accordingly, the associated public risk reduction is estimated to be 3.3 man-rem/RY and 7.1 man-rem/RY for PWRs and BWRs, respectively.

There is a total of 42 operating plants affected by this issue: 8 PWRs with an average remaining life of 27.7 years and 34 BWRs with an average remaining life of 25.2 years. For the 8 affected PWRs, the estimated risk reduction is [(8)(27.7)(3.3)] man-rem or 731 man-rem. For the 34 affected BWRs, the estimated risk reduction is [(34)(25.2)(7.1)] man-rem or 6,083 man-rem. Thus, the average risk reduction is approximately 162 man-rem/reactor.

Cost Estimate

For the purpose of this analysis, the plants affected by this issue are divided into two groups: Group 1, consisting of plants at which no design modifications are possible that would permit testing of the RPS at full power; and Group 2, consisting of plants that could possibly implement design modifications that would permit this testing. It was assumed for cost estimating purposes that the affected plants are divided equally into these two groups (21 plants each) and have an average remaining life of 26.9 years.

Industry Cost: The implementation of the possible solution for Group 1 plants requires 16 man-weeks/plant broken down as follows:

Inspection/review of current plant configuration	= 1 man-week
Researching possible design modifications	= 3 man-weeks
Analyze/justify deviations from regulatory requirements	= 4 man-weeks
Technical specification changes and associated technical/legal/administrative support	= 8 man-weeks

At approximately $2,270/man-week, the cost of implementation for Group 1 plants is estimated to be (16 man-week/plant)($2,270/man-week) or $36,000/plant. The implementation cost for Group 2 plants is estimated to consist of about $50,000/plant hardware costs and about 21 man-weeks/plant of labor itemized as follows:

Inspection/review of current plant configuration	= 1 man-week
Design modifications	= 3 man-weeks
Install and test design modifications	= 16 man-weeks
Revise testing procedures	= 2 man-weeks

Similarly, at $2,270/man-week, the labor cost is estimated to be (21 man-weeks/plant)($2,270/man-week) or $48,000/plant. Therefore, the total implementation cost for Group 2 plants is ($48,000/plant + $50,000/plant) or approximately $100,000/plant. Thus, the average implementation cost for the 42 affected reactors is $68,000/plant.

It was assumed that Group 1 plants will require additional inspection activities during outages associated with assuring the operability of the relays in the RPS. It was estimated that an additional 4 man-hours/relay (i.e., those 20 relays that cannot be tested at power) would be required every 6 months for Group 1 plants for a total of 160 man-hours/RY. For Group 2 plants, it was estimated that an additional 2 man-hours/relay will be required every 6 months for a total of 80 man-hours/RY. Since most of the work is in radiation zones, a 75% utilization factor for labor (210 man-hours/RY for Group 1 plants and 110 man-hours/RY for Group 2 plants) was assumed. At $2,270/man-week, maintenance and operation costs for Group 1 and Group 2 plants are estimated to be $12,000/RY and $6,200/RY, respectively. Using a 5% discount rate, the present worth of the recurring costs associated with plant maintenance and operation for Group 1 and 2 plants are $6,700/RY and $3,400/RY, respectively. Thus, the estimated operations and maintenance costs are $180,000/plant and $91,000/plant for Group 1 and Group 2 plants, respectively, and the average cost for all affected plants is $136,000/plant.

NRC Cost: NRC resource requirements consist of preparation of a generic letter to the affected plants to inform them of the potential problems and requiring licensee inspection/review of the RPS testing capabilities, as well as the technical analyses and/or design modifications needed to implement the proposed resolutions. This effort is estimated to require 6 man-weeks of NRC labor or $14,000. For the 42 affected plants, this cost averages $330/plant.

In addition, it was estimated that approximately 12 man-weeks (or $27,000/plant) of NRC labor is required for each Group 1 plant to review and approve licensee evaluations and technical specification changes. For each Group 2 plant, it is estimated that 10 man-weeks (or $23,000/plant) will be required for the review and approval of licensee evaluation, proposed design modifications, and technical specification changes. Thus, the average NRC cost for this effort is $25,000/plant for the 42 affected plants.

Inspection-related costs for each plant is about $4,600/year for the remaining life of the affected plants. At a 5% discount rate, this translates to a present worth of $2,600/RY. This cost is $70,000/plant based on the average remaining life of the affected plants.

Total Cost: Based on the above estimates, the average cost for implementing the possible solutions is $[68,000 + 136,000 + 330 + 25,000 + 70,000]/plant or approximately $0.3M/plant.

Value/Impact Assessment

Based on a potential public risk reduction of 162 man-rem/reactor and an average cost of $0.3M/reactor, the value/impact score is given by:

$$S = \frac{162 \text{ man-rem/reactor}}{\$0.3\text{M/reactor}}$$

$$= 540 \text{ man-rem/\$M}$$

Other Considerations

It was estimated that, for Group 1 plants, 1 man-week of utility labor in a radiation zone is required to inspect the non-testable relays and review the system design. Group 2 plants would be subjected to this review and would also require an additional 10 man-weeks to install the design modifications and 4 man-weeks to test the modified system. It was assumed that testing is performed outside containment so the dose rate is 2.5 millirem/hr. It is further assumed that the work involves a 75% utilization factor. The implementation dose is, therefore, estimated to be about 1 man-rem/plant.

It was estimated that, for Group 1 plants, operation and maintenance would require additional inspection activities during plant outages associated with assuring the operability of the relays in the RPS. It is estimated that a total of 160 man-hours/RY would be required for Group 1 plants. For Group 2 plants, it was estimated that the labor requirements are 110 man-hours/RY in a radiation zone. Assuming a 75% utilization factor, the total operation and maintenance dose is estimated to be about 12 man-rem/plant.

CONCLUSION

The estimated potential public risk reduction resulting from improvement in the on-line testability for the RPS at some older plants is significant. The value/impact score derived above indicates a medium priority. Neglecting the ESFAS relays may result in an underprediction of the total potential risk reduction. Experience has shown that testing of protection systems at power can have the potential for subtle interactions with other safety systems and/or plant operation that might result in negative effects on plant risk (i.e., an increase in plant risk). In addition, the negative aspects of increased testing (human error and reduced redundancy) may also produce a competing impact on plant risk. Based on these considerations and the value/impact score, this issue was given a MEDIUM priority ranking.

REFERENCES

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

1271. Memorandum for T. Speis from R. Bernero, "Request for Prioritization of Potential Generic Issue Per Office Letter No. 40," August 4, 1985.

1272. Memorandum for R. Mattson from F. Rosa, "Combustion Engineering Standard Technical Specifications (NUREG-0212) - Proposed Revision 3 - Relay Testing," October 8, 1982.

Management and control indicators used in GIMCS are defined as follows:

1. Issue No. - Generic Issue Number

2. Title - Generic Issue Title

3. Identification Date - Date the issue was identified

4. Prioritization Date - The date that the prioritization evaluation was approved by the RES Director

5. Type - Generic Safety (GSI), Licensing (LI), or Regulatory Impact (RI).

6. Priority - High (H) or Medium (M)

7. Task Manager - Name of assigned individual responsible for resolution

8. Office/Div/Br - The Office, Division, and Branch of the Task Manager who has lead responsibility for resolving the issue.

9. Action Level
   - Active - Technical assistance funds appropriated for resolution and/or Task Manager actively pursuing resolution.
   - Inactive - No technical assistance funds appropriated for resolution, Task Manager assigned to more important work, or no Task Manager assigned
   - Resolved - All necessary work has been completed and no additional resources will be expended

10. Status - Coded summary as follows: NR (Nearly-Resolved); 3A (Resolved with requirements); 3B (Resolved with no requirements); 5 (Licensing on Regulatory Impact issue that should be assigned resources for completion)

11. TAC Number - Task Action Control (TAC) number assigned to the issue

12. Resolution Date - Scheduled resolution date for the issue

13. Work Authorization - Who or what authorized work to be done on the issue

14. FIN - Financial identification number assigned to contract (if any) for technical assistance

15. Contractor - Contractor name

16. Contract Title - Contract Title (if contract issued)

17. Work Scope - Describes briefly the work necessary to technically resolve and complete the generic issue

18. Status - Describes current status of work

19. Affected Documents - Identifies documents into which the technical resolution will be incorporated

20. Problem/Resolution - Identifies problem areas and describes what actions are necessary to resolve them

21. Milestones - Selected significant milestones: the "original" scheduled dates reflect the original Task Action Plan; changes in the original scheduled dates are listed under "Current;" and actual completion dates are listed under "Actual"