MAINTENANCE INDICATOR DEMONSTRATION PROJECT

May 1990

Report Prepared By:

U.S. Nuclear Regulator Commission
Office for Analysis and Evaluation of Operational Data

EXECUTIVE SUMMARY

In response to the Commission's direction in the Staff Requirements Memorandum on SECY 89-143/COMLZ-89-21 "Amendment to 10CFR50 Related to Maintenance of Nuclear Power Plants," June 26, 1989, the staff initiated a "demonstration project" for the development of maintenance performance indicators. This report documents the lessons and results of the Demonstration Project.

Candidate utilities for the Demonstration Project were identified by the staff based upon characteristics such as nuclear steam supply system (NSSS) design, plant age and power rating, utility organizational size or number of plants operated, and location. Through the coordination of the Nuclear Management and Resources Council (NUMARC), six utilities volunteered to participate and provide a member to the Project group. The six utilities were: Commonwealth Edison Company, Duke Power Company, Northeast Nuclear Energy Company, Rochester Gas and Electric, Southern California Edison Company, and System Energy Resources, Incorporated. The utility participants agreed to a project limited in scope to the review of the NRC staff's proposed maintenance effectiveness indicator.

The Demonstration Project was conducted through a series of centralized meetings of the Project group and individual site visits between September 1989 and March 1990. The elements of the Demonstration Project were: presentation of the NRC initiative to the utilities, data review and analysis of the proposed indicator by the participating utilities and INPO, plant specific discussions of maintenance management and monitoring techniques, and further development activities by the staff. Individual meetings with each of the participating utilities typically took one and one-half days and involved their maintenance managers, along with members of their reliability or performance assessment groups. The Project group was well rounded with representation from utility maintenance, operations, licensing, and performance or reliability assessment organizations.

The industry participants did not agree that the NRC staff's proposed maintenance indicator was a measure of maintenance effectiveness. This disagreement arises from the industry's limited definition of maintenance versus the NRC's broad definition of maintenance, as described in the policy statement. The staff believes that consensus was reached on specific improvements to the proposed maintenance indicator. These improvements involve the indicator construction, calculation, and use.

Based upon AEOD's perspective on the issues that arose during the Demonstration Project, the following changes are suggested:

1. Revise the algorithm used in calculating the indicator to eliminate "ghost ticks" and capture "shadow ticks." Two alternative methods developed and being tested by the staff were introduced to the Demonstration Project during the March 1990 joint meeting.

2. Modify the overall indicator to include both system-based and component-based indications. The calculations and displays are being modified to also show component-based indications.

3. The staff should obtain critical components lists from participating utilities and determine if some of the components monitored by the present indicator could be deleted.

4. Modifications to the list of components to be monitored should be explored by the staff to include more safety system equipment and refine the previous scope.

5. Continue to encourage improvement in NPRDS participation and support the initiatives in the Industry Action Plan regarding improving NPRDS data quality.

6. Encourage NUMARC to include a specific element in the Industry Action Plan that addresses improving the quality of maintenance documentation regarding the nature of the equipment failures (cause and function impact), and assuring that adequate resources for NPRDS reporting are provided during outage periods.

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INTRODUCTION

In response to the Commission's direction in June 1989,[1] the Nuclear Regulatory Commission (NRC) staff initiated a "demonstration project" for the development of maintenance performance indicators. The staff identified candidate utilities based upon characteristics such as NSSS design, plant age and power rating, utility organizational size or number of plants operated, and location. Through the coordination of the Nuclear Management and Resources Council (NUMARC), the Institute of Nuclear Power Operations (INPO) and six utilities agreed to participate. The six utilities in the Project were: Commonwealth Edison Company, Duke Power Company, Northeast Utilities, Rochester Gas and Electric, Southern California Edison Company, and System Energy Resources, Incorporated. These industry participants agreed to a project limited in scope to the review of the NRC staff's proposed maintenance effectiveness indicator[2].

The Demonstration Project included the following elements: presentation of the NRC indicator to the utilities; NRC staff preparation of computer files and associated information, including presentations of failure records for which the proposed indicator was used to develop a representation of maintenance effectiveness; data review and analysis by the participating utilities; analysis by INPO; substantive discussions of maintenance management and monitoring techniques with plant staffs; further development activities by the staff; and working discussions of the Project group members to formulate results. Meetings with individual utilities generally involved their maintenance managers and the reliability or performance assessment groups (Appendix A). These meetings, which were typically one and one-half days long, followed the same basic agenda (Appendix B). The Project group was well rounded with representation from utility maintenance, operations, licensing, and performance or reliability assessment organizations.

The Demonstration Project participants worked toward consensus on issues associated with a performance indicator to monitor the effectiveness of maintenance at domestic nuclear power plants. The staff believes that some technical consensus was reached on various methods to improve the NRC staff's proposed indicator. These included changes to the indicator construction and calculation, the identification of potential improvements to the Nuclear Plant Reliability Data System (NPRDS), and, to some extent, use of the indicator. However, fundamental differences in perspectives on what constitutes maintenance functions resulted in disagreement over whether the indicator was a measure of maintenance effectiveness.

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1 Staff Requirements Memorandum on SECY 89-143/COMLZ-89-21 - Amendment to 10 CFR 50 Related to Maintenance of Nuclear Power Plants, June 26, 1989

2 The development and previous validation efforts regarding the NRC staff's proposed maintenance indicator have been documented in two reports: AEOD/S804B, "Application of the NPRDS for Maintenance Effectiveness Monitoring," issued in January 1989, and the EG&G Idaho, Inc. report, "Maintenance Effectiveness Indicator," issued in October 1989.

Typically, the maintenance manager does not control all the elements of the broadly defined maintenance process, but feels accountable for anything labeled "maintenance." The proposed indicator is programmatic by design, and is premised on the broad view of maintenance as outlined in the NRC Policy Statement on maintenance and industry guidelines. However, this view of maintenance and the current configuration of the indicator do not match up in a practical way with traditional maintenance line organizations at the sites. Thus, it may be difficult for plant staffs to benefit in a direct way from the proposed indicator in its current form. Variations of the indicator to make it more useful for plant staffs were discussed, including component scopes consistent with reliability-centered maintenance (RCM) programs, and calculating the changes in failures by component type as well as by system. Potential changes to the indicator to address these concerns were also discussed, including both the indicator construction and the calculation technique.

INDICATOR TECHNICAL ISSUES

The technical review by the participating utilities focused on the construction of the indicator, the equipment covered by the indicator, the alignment of the indicator with the utility maintenance program (nexus to maintenance), and the quality of the data that supported the indicator. The staff believes that consensus was achieved on selected improvements to the indicator.

Indicator Construction

The indicator construction issues refer to the calculational technique employed to generate the indications from a plant-specific database. Two issues emerged that are being addressed as a result of the Demonstration Project. These are: (1) ghost and shadowed ticks and (2) failure grouping.

Ghost and Shadow Ticks - In special cases, an indication would occur in a month in which no component failures were discovered, or the number of failures declined from the previous month. This phenomenon was referred to as a "ghost tick." The original algorithm created an indication based upon a change in the average of a month-to-month count of component failures. As a result, a high number of failures discovered in one month would carry over its impact into the average calculation for the subsequent month even though no new failures or fewer failures were discovered in that month. For the case of no new failures, a utility charged with troubleshooting the cause for its indications would find no basis for the indication in the month assigned. Although this feature served as a measure of the magnitude of the first month's component failures, it was misleading. Conversely, the original calculation algorithm also led to the masking of some significant failure changes. These indications which were not generated were known as "shadow ticks." In this case, indications were not generated for significant failure changes because preceding significant increases in failures overshadowed the two-month average associated with the later failure increase. Two alternative calculational techniques were developed and are being tested by the staff. They are described in Appendix C.

Failure Grouping - The issue of failure grouping arose from the consideration that the indicator (clusters of failures that caused an indication) should be amenable to root cause analysis by the utility. The original indicator was calculated based on the change in the failures of a selected set of

components (Outage Dominating Equipment [ODE]) within a system. This method produced indications that were, in many cases, due to the failure of different types of components (e.g., circuit breakers, pumps). This arrangement was consistent with the maintenance approach of some utilities in the Demonstration Project since systems were often made available for maintenance during a certain chronological interval, and the discovery of failures would tend to cluster (indicate) by system. In addition, the approach provided a usable tool that enhanced accountability for plants with systems engineers. However, other members of the Project group noted that this method would result in complicating the cause analysis. They requested a second version of the indicator that grouped indications by type of component. This method enhanced the root cause evaluation.

Equipment Selection

The equipment selection for the proposed indicator was the subject of review during the Demonstration Project. Two aspects are worthy of note. First, the staff's original equipment selection assumptions were relatively good. Second, the utilities preferred that the equipment selection reflect the plant's maintenance approach.

The original equipment selection for the indicator was restricted to achieve maximum reporting consistency across plants. NPRDS reporting is a function of the initiation and processing of corrective maintenance work orders. To accommodate the range of the aggressiveness of the operating crew and organization in work identification, a set of equipment was selected for the indicator that would likely be the subject of timely repair and work order processing. This set of equipment was that needed to support plant operation. In general, the staff's assumption was affirmed regarding the assurance that this set of equipment would be the subject of closer scrutiny, and hence, less reporting variability. Some licensees in the Demonstration Project had created a similar list of components based upon their operating experience. These components were then the subject of special oversight. This visibility helped ensure that the work order flow and information contained on the NPRDS record were better than average. Participating licensees also noted that the same maintenance program and practices are employed on balance-of-plant (BOP) equipment and safety equipment. Therefore, the maintenance quality on this set of equipment would likely be representative of the maintenance on all plant equipment.

The equipment selection for the indicator may not fully reflect the plant's approach to maintenance. The maintenance programs for some components may utilize a "run to failure" philosophy. Under such a philosophy, no systematic preventive maintenance (PM) is applied to the component. Only corrective maintenance is utilized. As a result, some component failures captured by the indicator would be allowed by the plant's maintenance program. Two of the Demonstration Project participants were conducting major RCM programs and viewed this as a major potential difference between the goal of the indicator and the results. RCM methodology, using cost/benefit analysis, may dictate such a philosophy based upon engineering analysis of the impact of the failure (i.e., the local, system, or plant level impact). Redundant components and technical specifications (TS) are among the considerations of that analysis. For example, equipment failures with only a local impact and no TS consequences may permit omission of any PM on the component. Two of the participating utilities agreed to furnish the staff with a list of their critical components (i.e., components contained in their PM program as a result of RCM activities), and the staff agreed to determine if some components should be eliminated or added to the list of components monitored

by the indicator. A general comment that was received from the participants was that the impact of each of the individual component failures being counted was, in most cases, not significant. Normal priorities of maintenance may allow some of the failures. The industry would prefer that the staff reduce the scope of monitoring to a smaller and more significant set of equipment, preferably only safety-related equipment. The proposed indicator monitored approximately 600 to 2000 components per plant to reflect a broad scope of the maintenance activities.

Nexus to Maintenance

The nexus of the indicator to maintenance was a major topic during the demonstration project. The staff reviewed selected component failures with each of the participating utilities. The utilities' analyses of these failures and the indicator consumed up to 6000 person hours and used all of the information available, including the memory of individuals. Therefore, their cause analysis went far beyond that afforded the staff through review of the narrative descriptions of the causes contained in the NPRDS failure record. Based upon a review of the NPRDS records, the staff had found that 84% of the component failures that comprised the indicator were related to maintenance, under the NRC's perspective of maintenance. During the Demonstration Project, the utilities found that about 14% of such failures were due to maintenance (primarily errors of commission), under their perspective. The major differences between these failure categorizations were associated with failures that the staff assigned to maintenance but which the industry assigned to wearout, design/manufacturing/application, random, or unknown causes.

Many problems that arise from design or application deficiencies are responded to through preventive maintenance measures. The industry asserted that the indicator did not measure maintenance effectiveness since the root cause for the failures comprising the indication was not maintenance-related, under their definition. For example, a utility would argue that charging pump failures or feedwater pump seal failures were due to the original design of the equipment. However, during the discussions, the staff noted that the solution to the problem was through the plant's maintenance program; that the occurrence or disappearance of the failures was a direct result of the preventive maintenance program; and that the indicator was measuring changes in failure frequencies resulting from that program.

Another major cause for failures that, from the viewpoint of the industry, clouds the relationship of the indicator to maintenance is wearout. Specifically, the industry categorized many failures not as maintenance, but as "first of a kind wearout." This category contained many failures that the staff contended could have been detected and repaired at the incipient failure stage through a predictive maintenance program or an aggressive preventive maintenance program. If detected and repaired as incipient failures (prior to the component function being degraded below specification), they would have escaped the indicator. Again, as in the previous example, first failures were frequently addressed by preventive maintenance. If a component (e.g., transmitter) continually failed after three years in a claimed design life of five years, the utility would initiate a preventive replacement at the earlier point, thereby eliminating the failures. The indicator would detect the change as a result of improved maintenance and the dispute regarding the initial cause of the failure is moot relevant to the integrity of the indicator.

This fundamental difference in perspective between the staff and the participating utilities on the nexus of component failures to maintenance came to be referred to in the Demonstration Project as "Big M versus Little m." These differences were graphically illustrated during the Demonstration Project.

During the proof-of-concept phase of the development of the proposed indicator, the staff categorized the causes for approximately 4000 NPRDS failures based on the failure narratives. These narratives were sampled from the periods of ODE component failure history which generated indications. This categorization represented the "Big M" perspective. The results of this categorization can be seen in Figure 1.

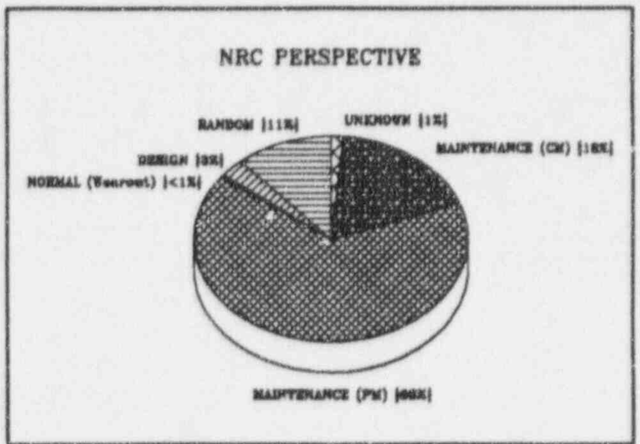

Figure 1. Nexus to Maintenance - NRC Perspective

The categories shown in Figure 1 should be understood as follows: The failures assigned to this category could be reduced by improvements in that programmatic area. For example, failures associated with the "PM" category were judged to be reducible by either improved implementation of an existing PM program, such as extending the program to cover additional equipment, or by instituting a more extensive PM program, such as using vibration analysis or periodic oil sampling. Two cases drawn from the documentation of recent NRC maintenance inspection results serve to further illustrate this PM assignment. In the first case, four forced outages involved degradation of reactor recirculation pump seals. To address this problem, the licensee initiated a program to collect and analyze reactor recirculation pump shaft vibration data, and has modified the seal replacement frequency.[3] In the second case, a turbine-driven auxiliary feedwater pump oversped and tripped on start. The cause was traced to lack of a PM program for periodic flushing of the governor as recommended in the vendor technical manual.[4] In both cases, the staff would assign the failure to the "PM" category.

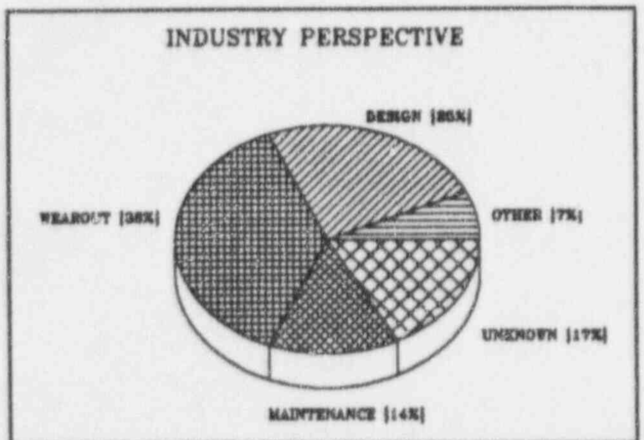

Figure 2. Nexus to Maintenance - Industry Perspective

Figure 2 shows the "Little m" perspective. It was developed during the Demonstration Project by the utility participants with the assistance of INPO and captured distinctions

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[3] Letter from A. B. Davis, NRC, to C. Reed, CECo, transmitting initial SALP 8 Report for the Quad Cities Nuclear Plant, February, 2, 1990.

[4] Letter from L. Reyes, NRC, to J. Goldberg, FPL, transmitting Notice of Violation for the St. Lucie facility, March 14, 1990.

they felt important in determining the nexus to maintenance. These distinctions were also brought out in the review of ODE failures the staff considered related to maintenance during site visits.

"Design" constitutes a large percentage in Figure 2, about eight times larger than the amount assigned by the staff. Such a difference is understandable in that the regulatory perspective of maintenance includes the feedback of experience gained through engineering and design modifications used to eliminate component performance problems, and over time, this process does achieve improvements. Examples of this that were discussed in some detail in the Demonstration Project included the improvement in charging pump performance at Ginna, the improvement in service water pump performance at Grand Gulf, the planned upgrading of charging pumps (replacement of blocks with new design/material) at San Onofre 2&3, and increased surveillance frequency on recirculation pump pressure switches to compensate for drift before their function was impaired. In all these cases, the number of failures experienced decreased or should decrease, thereby reflecting improvement. In other cases, however, failures would continue to occur at about the same rate because, as discussed for Millstone 3, utility studies showed that it was cost-beneficial and safe to simply periodically repair a marginally designed main feedwater pump seal rather than to pursue a design improvement.

<u>NPRDS Data Quality</u>

The utility participants stated that NPRDS data provides information on maintenance, but quality limitations impact its usefulness for a maintenance indicator used by the regulator. There is consensus between the staff and the industry that continued improvement and strengthening of NPRDS is needed.[5] In particular, the utility participants felt that a source of inconsistency in NPRDS reporting was the determination of the existence of a degraded component state needed to trigger NPRDS reportability. Overreporting of minor or incipient conditions revealed by an aggressive and proactive PM program as degraded failures would result in relatively more failures being used in the indicator, and potentially a greater magnitude in the indicator over time. However, regardless of any overall NPRDS data quality improvements, the data can still be used to determine trends at individual plants.

The proposed indicator itself is designed to be benign to proactive preventive or predictive maintenance. This was accomplished by only including NPRDS failures designated by the utility as "immediate" or "degraded". These terms are defined in NPRDS as follows:

Immediate - A failure that is sudden and complete.

Degraded - A failure that is gradual, partial, or both. The component degrades to a level that, in effect, is a termination of the ability to perform its required function. This code should be chosen when a system of component does not satisfy the minimum acceptable performance criteria for a specific function or when a component must be removed from service or isolated to perform corrective maintenance.

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[5] The revised Policy Statement on Maintenance states in part "The Commission encourages the use of the industry-wide NPRDS data..., including improved industry use of and participation in the NPRDS to gauge the effectiveness of maintenance."

Proactive maintenance would identify incipient conditions, defined as an imperfection in the state or condition of a component that could result in a degraded or immediate failure if corrective action is not taken. These incipient conditions would be reversed by PM prior to the component entering a degraded condition where function was impaired, or such impairment was imminent. An incipient designation or code indicates an optional record, since failure has not occurred. This code is also used by INPO to classify records judged not to be failures during the INPO failure audit process. NPRDS documentation provides extensive guidance for making this determination.

The proposed indicator should not penalize proactive preventive and predictive maintenance. It's important that incipient conditions discovered by these programs not be interpreted as degraded failures in the use of the indicator. Improvement of the quality of maintenance work orders appears essential to achieving improvement in NPRDS quality. The utility participants felt that work orders often do not contain enough detail to make a proper determination. The industry also feels that the lack of detail in work orders clouds root cause documentation and impacts the diagnostic value of the indicator. Also, timely maintenance work request close-out and associated NPRDS reporting is needed to capture important details.[6] These difficulties can be addressed through strengthening the quality of the maintenance work order documentation process, for example as done at Grand Gulf through a dedicated closeout Engineering Review Group (ERG), and through greater rigor in the quality assurance review conducted by INPO.

Grand Gulf has established the ERG to improve the quality and timeliness of maintenance documentation and closeout. The charter of the ERG, as created within the Performance and System Engineering Department, is to perform a final, independent review of maintenance work orders prior to closeout. Grand Gulf has tasked this group with ensuring work orders reflect adequate details of the identified problem, including the overall work scope, root cause, corrective actions taken, and component failures. The ERG represents a plant improvement with the potential for a direct impact on maintenance indicator development, addressing the concerns expressed about the quality of NPRDS reporting and its effect on the indicator. A group such as the ERG provides additional assurance that the failure information documented in the maintenance work orders (MWOs) is accurate and complete. This, in turn, helps assure that the subset being reported to the NPRDS is accurate and complete.

The specific duties of the ERG consist of:

1. Reviewing completed work orders for consistency,
2. Obtaining predictive maintenance data for trending,
3. Providing reports to system engineers for analysis,
4. Maintaining control of the surveillance tracking program,
5. Entering all MWOs into SIMS for component failure trending.

The ERG consists of a supervisor, three full time engineers, two clerical personnel, and two engineering technicians.

[6] The latest staff assessment of NPRDS is that reporting has become less timely. Failures should be in the system within 90 days of the discovery date.

The Industry Action Plan for improving maintenance identified the need for focused effort on the NPRDS to improve the industry's effectiveness in monitoring and maintaining the reliability of important plant equipment. Specifically, INPO and the utilities will upgrade NPRDS effectiveness by improving data quality and expanding the scope to include additional selected balance-of-plant equipment.

Recommended Approach:

1. Revise the algorithm used in calculating the indicator to eliminate "ghost ticks" and capture "shadow ticks." Two alternative methods developed and being tested by the staff were introduced to the Demonstration Project during the March 1990 joint meeting.

2. Modify the overall indicator to include both system-based and component-based indications. The calculations and displays are being modified to also show component-based indications.

3. The staff should obtain critical components lists from participating utilities and determine if some of the components monitored by the present indicator could be deleted.

4. Modifications to the list of components to be monitored should be explored by the staff to include more safety system equipment and refine the previous scope.

5. Continue to encourage improvement in NPRDS participation and support the initiatives in the Industry Action Plan regarding improving NPRDS data quality.

6. Encourage NUMARC to include a specific element in the Industry Action Plan that addresses improving the quality of maintenance documentation regarding the nature of the equipment failures (cause and function impact), and assuring that adequate resources for NPRDS reporting are provided during outage periods.

APPENDIX A

SUMMARIES OF MEETINGS WITH DEMONSTRATION PROJECT

UTILITY PARTICIPANTS

This Appendix contains copies of the NRC minutes for the individual meetings that were held with the six utility participants in the Demonstration Project. The minutes are arranged in the following chronological order:

MEMORANDUM FOR: Thomas M. Novak, Director
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

FROM: Mark H. Williams, Chief
Trends and Patterns Analysis Branch
Office for Analysis and Evaluation
of Operational Data

SUBJECT: MINUTES OF COMMONWEALTH EDISON/NUMARC/NRC
NOVEMBER 29-30, 1989 MEETING

On November 29-30, 1989, representatives from the NRC staff met with the Commonwealth Edison staff and a representative from the Nuclear Management and Resources Council (NUMARC) at the Chicago Office of Commonwealth Edison. The meeting was scheduled as part of the Maintenance Indicator Demonstration Project to discuss the staff's proposed Maintenance Effectiveness Indicator (MEI). This meeting was the first in a series of meetings to be held with individual utilities as part of the MEI Demonstration Project. A list of attendees is attached.

The NRC staff presented the detail and logic followed by the staff during the development process for the proposed maintenance indicator. The intent of this presentation was to familiarize utility personnel with all the details necessary for understanding the proposed maintenance indicator.

During the course of the meeting it was determined that Commonwealth Edison is moving toward monitoring equipment (component) performance. Monitoring of component reliability by Commonwealth Edison is in general consistent with the logic being followed by the NRC staff during the development of the proposed maintenance indicator. In addition, it was determined that: 1) utilization of component failures to measure the quality of maintenance is appropriate and useful, 2) utilization of failure rate increase methods is a reasonable way to approach the detection of changes in maintenance effects, and 3) the ODE equipment list/selection for the indicator is generally consistent with Commonwealth Edison's priority listing for equipment availability.

Feedback from Commonwealth Edison was in general positive and constructive. The following recommendations were made: (1) The current methods used to calculate the MEI may have to be revisited to make the indicator more useful to plant staff, e.g., consider grouping failures by component type and by system, (2) the indicator should be sensitive enough to reflect on-going programs to address specific fixes for a given component; i e., check valves, MOV's, pumps, etc., (3) additional sources of data beyond NPRDS (GADS, Greybook) may be useful to better describe ODE equipment performance.

Mark H. Williams, Chief
Trends and Patterns Analysis Branch
Office for Analysis and Evaluation
of Operational Data

cc: E. Jordan, AEOD
W. Smith, NUMARC
P. Kuhel, CECo
PDR

ATTENDANCE LIST

November 29-30, 1989 Meeting

MAINTENANCE INDICATOR DEMONSTRATION PROJECT

NAME	ORGANIZATION
Paul Kuhel	Commonwealth Edison
Martin G. Kief	Commonwealth Edison
Don Eggett	Commonwealth Edison
Robert Lazon	Commonwealth Edison
Thomas Kovach	Commonwealth Edison
Lee A. Sues	Commonwealth Edison
Walt Smith	NUMARC
Larry Bell	NRC/AEOD
Pat O'Reilly	NRC/AEOD
Mark Williams	NRC/AEOD
Thomas Novak	NRC/AEOD

MEMORANDUM FOR: Thomas M. Novak, Director
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

FROM: Mark H. Williams, Chief
Trends and Patterns Analysis Branch
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

SUBJECT: SUMMARY OF DECEMBER 12-13, 1989 MEETING WITH SOUTHERN CALIFORNIA EDISON COMPANY REGARDING MAINTENANCE INDICATOR DEVELOPMENT

On December 12-13, 1989, members of the Nuclear Regulatory Commission (NRC) staff met with representatives of Southern California Edison Company (SCE) and the Nuclear Utilities Management and Resources Council (NUMARC) at the San Onofre Nuclear Generating Station (SONGS) site to discuss maintenance indicator development. This meeting was a followup to the October 13, 1989 meeting of the NRC/Industry Maintenance Indicator Demonstration Project.

A list of meeting attendees is enclosed.

The NRC staff presented the detail and logic which the staff followed during the development of the staff's proposed Maintenance Indicator. The purpose of this presentation was to familiarize SCE personnel with all of the detail necessary for understanding the proposed indicator.

SCE explained to the staff that, although they do not have an integrated program for measuring the effectiveness of their maintenance program, they do monitor a number of specific maintenance-related areas (e.g., non-outage productivity, thermal performance, vibration monitoring, rework monitoring, and oil sampling).

The primary issue which was discussed during the meeting was the link between the NRC's proposed indicator and maintenance. This was accomplished by:

(1) Listing representative cases of component failures comprising the NRC's indicator which the staff had designated as maintenance-related and SCE has not.

(2) Analyzing the failure narratives for the component failures identified in (1) above. The staff's analysis was based solely on the information contained in the narrative; SCE's analysis was based on all available information (including individual memory) at the site regarding specific failure.

(3) Discussing the difference in views of "maintenance-related" failures which, in turn, resulted in the following issues:

- SCE expressed the view that the first failure of a component, or the failure of a component after it has been in service for a long time, should not be necessarily considered as related to maintenance. On the other hand, it is not clear that such

failures should be excluded, since lack of maintenance attention or oversight regarding inclusion in a PM program could be the cause of the failure. The number of such failures captured by the indicator and their effect on the indicator has not been determined, but this area should be explored.

° SCE believed that "wearout" was an acceptable characterization of a failure cause, and that "wearout" failures should generally not be considered as related to maintenance. In general, the staff feels that prevention of wearout to the point of loss of function (failure) is the objective of a maintenance program, and thus failures assigned a "wearout" cause should be considered when assessing the performance of a maintenance program. Further, "wearout" may be used too frequently in lieu of more rigorous cause analysis.

° SCE indicated that a reliability centered maintenance (RCM) program could lead to a planned "run-to-failure" strategy for some equipment, and thus failures of that equipment should not be used as part of a maintenance indicator. In particular, condition directed RCM will allow selected components to reach a degraded failure state and thus generate an NPRDS failure report. SCE plans to review the list of equipment used in the candidate indicator and recommend modifications to address this issue. Related to this concern, SCE felt that there is some acceptable level of component failure associated with an effective maintenance program, but the indicator counts all failures in establishing trends, which implies that any failure is a result of maintenance ineffectiveness. The indicator uses failures across a broad spectrum of equipment over time to establish a trend, and in that framework no single failure is used to reach a conclusion about the effectiveness of the program. This concern could also be handled by putting an "error band" around the indicator.

° The concern about reporting incipient conditions as degraded failures to the NPRDS was also discussed. SCE indicated that some utility maintenance tracking systems might allow corrective action to be taken under the umbrella of preventive maintenance, and thus no failure report would be submitted to the NPRDS. This issue related to the completeness and consistency of NPRDS reporting.

Finally, a number of suggestions were made for improving the current indicator which led to the following items for future action:

(1) SCE will review the specific list of equipment monitored by the indicator for San Onofre Units 1, 2, and 3 and designate those components that should be allowed to run to failure including condition directed cases. Upon staff agreement with such a list, this may have the effect of reducing the number of first failures of a component contributing to the indications. The staff will provide SCE the pertinent engineering records for these three units to facilitate the review.

(2) The staff will develop a template or peer grouping for use in interpreting the calculated indicator. This will be cycle-based. No comparison across plants would be attempted except within the context of this template. Hence, the template would have the so-called "acceptance bands" mentioned previously.

(3) For future analyses, the staff will produce the indicator calculated by component type as well as by system. Selection of specific component types will be influenced by the component

types considered in a CFAR run. SCE will provide a list of the CFAR component types for this purpose.

(4) The staff will modify the indicator algorithm to eliminate the problem of "ghost ticks."

(5) The staff will determine the extent of the problem of different "levels" of degraded failures - those being discovered during operations versus those discovered during refueling outages (particularly under "open and inspect" conditions).

Mark H. Williams, Chief
Trends and Patterns Analysis Branch
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

Enclosure: As stated

cc: E. Jordan, AEOD
W. Smith, NUMARC
M. Rodin, SCE
PDR

ENCLOSURE

List of Attendees

SONGS - NRC MAINTENANCE INDICATOR MEETING

December 12 - 13, 1989

Name	Organization
Brian Katz*	Mgr. NSSSD
Don Evans*	SSSD
Ralph Sanders	SSSD
Robin Baker	Licensing
L.D. Brevig	Licensing
Fred Briggs	Sta. Tech.
A.D. Toth	NRC Region V
R.L. Dennig*	AEOD/NRC
Walt Smith*	NUMARC
Jack Rainsberry	Licensing
Mark Williams*	AEOD/NRC
Loyd Wright*	SSSD, Supv.
R.H. Bridenbecker	VP, Site Mgr.
Harold Ray	VP, NES&L
M.E. Rodin*	SSSD/Reliability
Pat O'Reilly*	AEOD/NRC
Barbara Aden	SSSD
Bob Levline*	SSSD/ERIN

Notes:

* Full time attendees

MEMORANDUM FOR: Thomas M. Novak, Director
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

FROM: Mark H Williams, Chief
Trends and Patterns Analysis Branch
Office for Analysis and Evaluation
of Operational Data

SUBJECT: SUMMARY FROM JANUARY 9-10, 1990 MEETING AT OCONEE

On January 9-10, 1990 we met with representatives of Duke Power and NUMARC to pursue the formulation of maintenance performance indicators. The list of attendees is attached. Discussions followed the agenda provided as Attachment 2, and were limited to the Oconee station since Duke staff indicated that no review had been performed for McGuire or Catawba. The Duke staff did invest a significant amount of time in analyzing the indicator for the Oconee case.

Item 2 of the agenda, the discussion of interim indicator results, raised issues on how the indicator would actually be used, and how much of a resource impact any additional indicator, technical merits aside, would have on Duke general office and plant staffs. The concern expressed by Duke staff was that any new indicator would require resources to respond. At a minimum, they would have to periodically review it and understand its implications. This would detract from other inplant reliability analyses already in process, e.g., CFAR, FATS. Their concern about such an impact is proportional to the degree that this indicator would be used based on its face value, e.g., absolute magnitude, without additional analysis and interpretation by knowledgeable individuals.

The NRC staff indicated that the proposed indicator was not intended for use without additional information on maintenance, for example, as found in inspection reports, and that use of any indicator alone as a basis for a regulatory decision or perspective on performance was contrary to NRC policy.

Item 3, root cause analysis of individual component failures, was accomplished by reviewing a selection of failures for ODE equipment. Based on the information in the failure narrative the staff classified these examples as maintenance related, while the utility had not. Of a total of 15 cases reviewed, the Duke staff believed that six could be related to maintenance (as they define it) in whole or in part. With the additional information provided by Duke, the staff concluded that 3 of the 15 cases were not related to maintenance (as the staff defines it based on the Commission policy statement). The participants disagreed on the remaining 6 cases, due to the differing definitions of what maintenance encompasses, differing understandings of what the term "maintenance related" means, and the suitability of the NPRDS guidance on what constitutes a degraded failure (which is used in the indicator) and an incipient condition (which is not used in the indicator).

The interpretation of "wearout" is a particular concern. Duke staff contends that wearout is a legitimate cause designation which relates to normal equipment service, and does not necessarily indicate deficient maintenance. On the contrary, Duke staff felt that wearout actually

may indicate proactive and desirable maintenance for either the incipient or degraded degrees of failure. The staff does not take issue with this contention per se, but argues only that degraded and immediate failures (where by definition a component cannot adequately perform one or more of its functions) attributed to wearout are relevant to evaluating the effectiveness of maintenance.

In general, the staff indicated that its definitions were consistent with the Commission policy statement on maintenance, with INPO industry guidelines, and current NPRDS reporting guidance on the degree of failure. Duke staff disagreed with the boundaries drawn by the staff in its interpretation of the scope of maintenance. The Duke staff further suggested that the NPRDS guidance on degree of failure, in the context of a proposed maintenance indicator, may be too conservative and result in capturing incipient conditions as degraded failures.

Under Item 5, Duke Power approaches to component failure trending, the Oconee staff provided information on a number of different efforts, either underway or in the formative stages, as described in Attachment 3. One database used for component failure trending purposes is the Failure And Trending module (FAT). This data base contains information for every maintenance work order that indicated a problem. It includes all failures that would be reported to NPRDS, but covers a much greater scope of equipment, and covers problems of a lower severity than those reportable as degraded or immediate failures for NPRDS. When comparing trends under Item 6, Duke staff used the flagging algorithm proposed by the staff in combination with FAT data and generally obtained more flags. No alternative algorithms or thresholds were tried. The Duke staff at Oconee is also making use of CFAR, which is based on NPRDS data and compares a plant against the industry for numerous component groupings and application-coded components using failures per component hour. However, CFAR does not currently provide a trendable indicator.

The Duke staff stated that the proposed indicator provided a measure of component failures, but that as currently calculated it did not line up with the Oconee maintenance organization, and thus would not provide useful feedback to the plant staff. The mechanical maintenance at Oconee is organized by type of component, while the instrumentation and electrical is organized by system. Thus, the system-based calculation underlying the cumulative indicator display, with its mix of different types of components, does not align with the responsibilities of their plant staff. In response, the staff explained that the proposed indicator was programmatic, and not constructed as a detailed feedback tool for taking corrective action. Adverse indicator trends would necessitate a broad review of the maintenance program and its implementation. Nonetheless, the indicator could be made more useful to plant staffs, for example by cutting the data by component type, as suggested earlier by Commonwealth Edison staff. Steps to make the indicator more useful are being pursued by the staff, in addition to eliminating mechanistic problems such as "ghost ticks."

The Oconee staff is also becoming used to interpreting the component failure rates provided by CFAR and prefers that similar statistics, i.e., failures normalized by component population, be used to avoid confusion. Given the preference for the CFAR-type approach, Duke staff indicated that they would try to develop a way to turn CFAR results into a trending tool. The Duke staff offered a number of alternatives for staff use in measuring maintenance effectiveness as presented in Attachment 4.

In summary, a number of issues concerning the indicator raised in previous discussions with the AHAC participants were again raised by the Duke staff:

Ascribing the first failure and wearout failures to maintenance,

The potential for counting failures that are discovered by PM and not severe enough to impact the component's primary function (due to some NPRDS failures being coded as "degraded" in accordance with guidance although they are felt to be incipient),

Not highlighting repeat failures or rework,

The presence of "ghost ticks,"

The degree of usefulness to the plant staff,

The need for multiple indicators to capture all the nuances of maintenance performance.

The Duke staff views the proposed indicator as an equipment trend indicator, and believes that a component failure oriented indicator is needed as part of a set to monitor maintenance. Duke staff maintained that more than one overall indicator was needed to monitor the maintenance process. The NRC staff agreed and noted that monitoring equipment failures, the focus of the NRC staff activities, was one useful and important measure of maintenance effectiveness that should be used with other utility indicators to assess and improve the maintenance process. The scope of equipment covered by the indicator (ODE) contained as a subset the equipment Duke would be concerned with given the same basis for selection. More than in previous discussions the Duke staff expressed concern about resources needed to deal with the indicator for response and diagnosis. In particular they felt that since they were already committed to periodic use of CFAR, the need for an indicator might be met by some modification of CFAR, thus saving engineering resources.

Mark H Williams, Chief
Trends and Patterns Analysis Branch
Office for Analysis and Evaluation
of Operational Data

Attachments: As stated

cc: E. Jordan, AEOD
W. Smith, NUMARC
S. Lindsey, Duke Power
L. Wiens, NRR
PDR

Attachment 1

Attendance
January 9-10, 1990 Meeting with Duke Power Company
Regarding Maintenance Indicators

Name	Office	Telephone Number
Bob Dennig	NRC/AEOD	301-492-4490
Tom Novak	NRC/AEOD	301-492-4484
Wayne Hallman	DPC/GO	704-373-2345
Walt Smith	NUMARC	202-872-1280
Bill Foster	DPC/ONS/MAINT.	803-885-3152
Mark Williams	NRC/AEOD	301-492-4480
Ronnie Henderson	DPC/ONS/MMSU	803-885-3152
Sam Hamrick	DPC/ONS/MMSU	803-885-3519
Stuart Lindsey	DPC/NUC. MAINT.	704-373-8768
Pierce Skinner	NRC/SRI-Oconee	803-882-6927
Dendy Clardy	DPC/ONS/MAINT.	803-885-3160

Attachment 2

AGENDA

JANUARY 9-10, 1990 MEETING WITH DUKE POWER COMPANY

REGARDING MAINTENANCE INDICATORS

(1) NRC presentation - Performance Indicator Development, Analysis Assumptions and Purpose of Meeting.

(2) Discussion of Interim Indicator Results.

(3) NPRDS Reporting of Component Failures Involving Outage-Dominating Equipment.

(4) Root Cause Analysis of Individual Component Failures of Outage-Dominating Equipment.

(5) Discussion of Duke Power's Programs/Approaches for Trending Equipment Failures and Failure Causes as They Relate to Maintenance ("FATS")

(6) Comparison of Maintenance Trend Information

(a) Trends Calculated with the NRC's Indicator
(b) Trends Calculated with Duke Power's Indicator(s)

Attachment 3

Outline of Trending Approaches at Oconee Nuclear Station

1) Communications from Work Execution Technicians and Planners to Maintenance Engineering of component failure trends and repeat actions recognized while planning and/or performing maintenance. This is an ongoing process and serves as an active feedback mechanism in the maintenance-triangle concept. Planners now have the capability to retrieve printed information sheets that show a component's corrective maintenance history while planning each work request. This enables the Planner to look for trends during the planning process. The history sheets are attached with the work request so that Work Execution can review as well.

2) Maintenance Engineers are accountable for defining and driving Technical Support Programs for components and systems. The TSP's include component trending activities. The Maintenance Engineers are expected to define and perform programmed maintenance in an "ownership" manner, and they monitor the performance and failures of their components on a regular basis. The Maintenance Engineers supply regular feedback and conduct meetings to inform appropriate Planning, Work Execution, Radiation Protection, Operations and Maintenance Management of actions that are needed for problem components discovered through trending or components that will be monitored closely for trends while operating. Maintenance Engineers maintain trend data in a variety of places ranging from personal files to computer data sets.

3) Some examples of Technical Support Programs where trending is ongoing are:

a. The Predictive Maintenance and Monitoring Program (PM2). This program includes the acquisition and trending of vibration and oil analysis data for rotating equipment. The responsible Maintenance Engineer monitors the data for adverse trends and prescribes corrective and preventive maintenance when trends indicate actions are necessary.

b. The pipe Erosion/Corrosion Control Program. This program includes the acquisition of pipe and fitting wall thicknesses that are maintained in a computer file. The responsible Maintenance Engineer monitors the data for trends that show wall thickness that are decreasing at an adverse rate. When trends are discovered, the Maintenance Engineer prescribes the appropriate actions.

c. Instrument procedures provide data sheets for I&E technicians to identify components where malfunctions or exceeded calibration tolerances are discovered. These data sheets are named Component Malfunction/Maximum Tolerance Limit Exceeded sheets. The data sheets are forwarded to the responsible Maintenance Engineers for evaluation, and the sheets are kept in I&E Maintenance Engineering files for trending data. The I&E Maintenance Engineers review the filed data for trends.

d. The I&E Maintenance Engineer responsible for the RPS system monitors the Reactor Coolant flow for deviations greater than one-half percent and trends that show increasing deviations. As increasing deviations are discovered, the Maintenance Engineer prescribes the necessary actions to prevent excessive deviations.

e. The I&E Maintenance Engineer responsible for the Control Rod Drive breakers monitors the trip times obtained during monthly Preventive Maintenance testing and trends the data for trip times that show increases towards a limit established by the engineer. The engineer prescribes necessary actions when adverse increases are apparent.

f. The Performance Group trends leak rate data, valve stroke times, pump performance etc., and notifies Maintenance when adverse trends are discovered.

g. Limitorque valve operator MOVATS and lubrication analysis data are trended by the responsible Maintenance Engineers for predictive maintenance purposes.

4) The following failure reports are provided to Maintenance Engineers for their use in trending components.

a. The "Value Report Card" is supplied to the Maintenance Valve Engineer after each Refueling Outage. This failure report identifies any corrective maintenance work requests written within the thirty-day window following the Refueling Outage. The engineer analyzes the identified valve failures for failure trends as well as work execution effectiveness.

b. The "Multiple Work Request Report" is supplied to both Mechanical and I&E Maintenance Engineering groups. This report identifies components that encounter multiple failures (not necessarily related) in a selected time period.

c. The "Average Failure Frequency Report" is supplied to both Mechanical and I&E Maintenance Engineering groups. This report develops failure rates or frequencies considering component populations, number of corrective maintenance work requests written within a selected time period for respective components and the amount of work hours expended.

d. The "Component Failure Analysis Report" (CFAR) is now being supplied to the Maintenance Engineering groups quarterly. CFAR identified Oconee's NPRDS components that are experiencing higher failure rates than similar component applications throughout the industry. NPRDS reports that are submitted are now being supplied to the corresponding Maintenance Engineers on a monthly basis with a summary sheet being sent to the Maintenance Engineering Manager.

e. Special failure reports are supplied to Maintenance Engineers as they request them and as the MMSU group discovers failures that indicate a need for further investigation. These reports are built from maintenance history data and failure data contained in the Equipment Database (EQDB), Nuclear Maintenance Database (NMDB) and the Failure and Trending module (FAT).

f. Future capabilities being considered are reports that identify rework, repeat failures, and corrective maintenance required following PMs.

5) Examples of other maintenance indicators trended at Oconee:

a. Oconee's Management Information System Report (MIS Report) is a monthly report that supplies a detailed accounting of work hours expended by types of work, the ratio of

Preventive Maintenance to Corrective Maintenance work hours, the number of high priority work requests written and closed out during the month, the work request backlog greater than 90 days, the status of each open work request and the responsible Planner. Each monthly issue is reviewed and trended by Maintenance Management.

b. Weekly audits of work requests by Planning Coordinators and Planning Manager for completeness and accuracy. One purpose of the audits is to trend the quality of information documented on work requests.

c. Housekeeping reports are used to trend Material Condition.

d. The Operations group identifies Control Room Annunciators and Instruments out of service monthly to the Planning Group for corrective action. Planning and Operations trend the monthly reports.

e. Others.

6) Indicators such as Availability Factor, Safety System Actuations, Forced Outage Rate, Corrective Maintenance Backlog, High Priority Work Requests, Ratio of PM to Total Maintenance, PMs Overdue, Thermal Performance, Capacity Factor and Number of Continuous Days of Operation have shown favorable trends during the past years and <u>indicate that Oconee's Maintenance Programs are effective in managing component failures.</u>

Attachment 4

*** PROPOSED OPTIONS ***

FOR

MAINTENANCE EFFECTIVENESS INDICATOR

OPTION 1: Utilize LER Forced Outage Rate Data

Reasons: * Both LER and Forced Outage Rate data are now reported to NRC under familiar reporting guidelines. This data is relatively pure and accessible for NRC use.

* Maintenance-related LER data would provide indications of those maintenance challenges to safety systems or design operating bases for a plant. Forced Outage Rate data captures the challenges to the major outage-causing equipment. Together they provide a good basic picture of a plant's maintenance without constructing another indicator.

Cost/Benefit: * Cost to the NRC and industry would be minimal. This data is well understood and will not require redundant analysis/review which would be necessitated by a new indicator.

Needs: * Better maintenance cause codes need to be defined for LER reporting. In addition, the current LER data would need to be reviewed and reclassified for a prior baseline period (e.g., 3 years backlit would probably give a good track record for trending). Based on a review of Oconee LER data for 3 years, this took about 45 minutes for all 3 units.

Option 2: Utilize some of the important "Maintenance Indicators"

Reasons: * A defined core of these maintenance indicators, when reviewed collectively, do provide a more accurate picture of Maintenance Program Effectiveness then any one indicator could. These are what most utilities use to measure their program effectiveness; therefore, the data is again well defined.

Cost/Benefit: * Cost to the NRC and industry would be minimal. This data is well understood and will not require redundant analysis/defense which would be necessitated by the new indicator.

Needs: * Both the industry and the NRC need to come to a more definitive agreement as to what "Maintenance" means. This will require definition of a core set of indicators that when looked at cumulatively provide indication of Maintenance Program health. Possibly a reliability/availability indicator needs to be added to the "Set" of accepted indicators.

<u>Option 3</u>: Utilize CFAR type report(s) or Reconstructed Indicator(s) based on Failure Data Grouped Component Types

Reasons: * Failure data <u>grouped by system</u> appears to be ineffective in correlating with other program indicators; therefore, any reliability type indicator(s) need to be grouped based on component groups similar to CFAR. This would provide some feedback on repeat failures. In effect, trending CFAR "hits" or failure rates would provide the same type of information and alleviate the extra cost to the industry of trending a duplicate indicator.

Cost/Benefit: * The cost for the NRC to use CFAR would not be as high but CFAR in its present form is still judged inadequate to represent Maintenance Program effectiveness. Thus even if CFAR is provided to the Commission, it will require some additional cost to reconstruct CFAR for the type of analysis desired. However, CFAR data is well understood and will not require redundant analysis/review which would be necessitated by the new indicator.

Needs: * If a new reliability indicator is generated then several major changes need to be incorporated to make it useful:

1. Grouping should be made by major critical component groups mutually agreed upon by the industry and the Commission.

2. Wearout should be allowed as a legitimate separate cause code not strictly maintenance related. Additional definition of legitimate wearout will be needed to satisfy both industry and the Commission.

3. Failure trending should account for population size of the group (i.e., % failures of a given population would provide some benefit for efficiency of maintenance).

4. Failure trending should be strictly plotted as total # of failures, or failure rate, or % failures for given population per quarter. If trigger levels are desired then Alert and Alarm levels should be established based on statistical confidence limits of population functional ability (i.e., something like a 90% confidence of 90% of the population being functionally operable during a given time period). An algorithm which averages failures should not be used.

5. A reliability indicator should not be used unilaterally to measure maintenance program effectiveness, but should be only one of several indicators evaluated. Also, the PM program should be accounted for in any maintenance indicator.

6. Impact of the failure needs to be evaluated and incorporated (e.g., was the failure significant to system operability and safety).

MEMORANDUM FOR: Thomas M. Novak, Director
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

FROM: Mark H. Williams, Chief
Trends and Patterns Analysis Branch
Office for Analysis and Evaluation
of Operational Data

SUBJECT: SUMMARY OF JANUARY 17-18, 1990 MEETING WITH ROCHESTER GAS & ELECTRIC CORPORATION REGARDING MAINTENANCE INDICATOR DEVELOPMENT

On January 17-18, 1990, members of the NRC staff met with representatives of Rochester Gas and Electric Corporation (RG&E), their consultant, ATESI, and the Nuclear Management and Resources Council (NUMARC) at the Ginna site to discuss maintenance indicator development. A list of meeting attendees is contained in Enclosure 1. Enclosure 2 contains the overall meeting agenda. Enclosure 3 is the agenda for RG&E presentations that discussed specific portions of the agenda items from Enclosure 2.

This meeting was a followup to the October 13, 1989 meeting of the NRC/Industry Maintenance Indicator Demonstration Project. The composition of the demonstration project represents a broad spectrum of utility organizations and sizes, as well as plant sizes and nuclear steam supply system designs and ages. RG&E was included in the demonstration project to gain insights regarding the monitoring of maintenance from the perspective of a relatively small utility operating a single, older plant - RG&E's Ginna plant. Ginna began commercial operation in 1970 with a two-loop Westinghouse-designed PWR having an electrical output of 470 MWe, and represents roughly one-half of the utility's electric generating capacity.

The NRC staff presented the detail and logic which were followed during the development of the staff's proposed Maintenance Indicator (MI). The purpose of this presentation was to familiarize RG&E personnel with all of the detail necessary for understanding the proposed indicator.

RG&E presented results of their assessment of the NRC's proposed indicator, which involved an RG&E staff effort of approximately 1000 manhours. This assessment, which included mathematical verification of the indicator algorithm and results of their analysis of individual NPRDS component failure narratives, focused on an example system (chemical and volume control system) that, according to the indicator, had equipment problems, and a discussion of the reliability-centered maintenance (RCM) program being implemented at the Ginna plant.

RG&E presented the background behind their RCM project, its system selection criteria, the RCM analysis and task methodology, and the RCM Living Program. The results of the RCM analysis determine which components will receive PM tasks designed to maintain component function.

The following major issues were discussed during the meeting:

(1) RG&E expressed concern that the staff's proposed indicator did not distinguish critical failures from failures which were not significant. They were concerned that use of this indicator could result in a plant's maintenance program focusing on relatively unimportant individual failures. RG&E stated that significant events which occurred at Ginna over the time span of interest were not tracked by the indicator. The staff explained that, as a programmatic indicator, the proposed indicator was not intended to track significant events. Rather, it was intended to track component failures across a broad spectrum of equipment over time to establish a trend on the premise that no single failure would be used to reach a conclusion about the effectiveness of the maintenance program.

(2) Definition of Maintenance - comparison of the results of independent reviews of example NPRDS failure narratives performed by RG&E and the NRC staff led to the issue whether failures which involved wearout or were first of a kind were maintenance-related.

RG&E reevaluated all of the NPRDS failures using a jury expertise approach, and, in their view, a low percentage could be attributed directly to "maintenance" (11%), as their organizational structure defines maintenance.

According to RG&E, intrinsic design reliability results in random failures for some components [e.g., components that rely on materials that degrade over time (capacitors, relays, seals)] which are expected and are not a result of ineffective maintenance.

A case in point was a group of failures involving the charging pumps. In these failures, the pump packing was found to be leaking, the packing was replaced, and the events were reported to the NPRDS as degraded failures. After several pump packing failures of this type, RG&E determined that the leaking packing was a wearout problem. The corrective action taken was to prepare a PM procedure to replace the pump packing periodically. Under current NPRDS reporting guidance, RG&E considers the packing replacement a wearout condition, and not a maintenance-related failure. The NRC staff commented that for this case, regardless of the cause of the first failure of the pump packing (wearout or maintenance-related), since the indicator would be tracking the failure history, it would show a valid improvement in the RG&E maintenance program when the new PM procedure for the pump was implemented. Therefore, the indicator in this case would measure a maintenance program improvement, and the question of whether the initial failures were due to wearout or lack of maintenance was moot.

RG&E pointed out that, independent of incipient or degraded reporting, the economic decisions exercised during the selection of the preventive maintenance activities or decisions not to maintain but replace when appropriate are treated negatively by the staff's proposed indicator. The indicator does not consider economic and ALARA considerations. This is related to the concern expressed in other meetings with project participants that there is some acceptable level of component failure rate associated with an effective maintenance program. However, the proposed indicator counts all failures in establishing trends, which implies that any failure is a result of maintenance ineffectiveness. To this concern, the staff has responded that the indicator uses failures across a broad spectrum of equipment over time to establish a trend, and in that framework, no single failure is used to reach a conclusion about the effectiveness of the

program. The staff believes that these concerns could be resolved by putting a band around the indicator which would identify the region of acceptability.

(3) Reliability-Centered Maintenance - Since the analysis is done on a component basis, this methodology may allow components to run to failure, or to a condition where corrective maintenance is required due to a loss of function, if a redundant component (i.e., another train or path) is available. The analysis used to identify this equipment considers the local impact, system impact, and plant impact of the component failure. There will be no system impact if all of its constituent trains are not taken down by the failure of the component.

RG&E stated that the RCM systems selected are predominately standby systems, whereas the systems monitored by the indicator are outage-dominating systems. The staff's proposed indicator does not currently cover most standby safety systems.

The staff pointed out that the proposed indicator can serve as a check on the adequacy of the RCM program and implementation. To ensure that the indicator maintains consistency across plants to the extent possible, the equipment scope of the RCM program should be included in the selection of equipment to be monitored by the indicator. In this vein, the list of equipment monitored by the indicator may be modified, contingent on recommendations received from the industry during the demonstration project.

From their review of the set of NPRDS failures, RG&E concluded that no PM Program activity at Ginna should be modified as a result of the failures aggregated under the indicator algorithm methodology. Other equipment failures have caused PM Program changes at Ginna.

Since the indicator for the Ginna plant remained below the average for PWRs of its type and size, with no adverse trends, over the entire period of interest, the staff would not have expected any PM Program changes to be made based on the indicator.

RG&E indicated there is significant risk in reliance on a single indicator to measure maintenance effectiveness; the staff's proposed indicator could penalize a good performer by lessening the priority for budgets being applied to maintenance if the indicator showed good performance. RG&E utilizes both process indicators (backlog) and industry performance indicators (i.e., availability) as measures of maintenance effectiveness. RG&E did identify the following two sets of indicators, one qualitative, the other quantitative, which they would propose using to monitor maintenance effectiveness:

Qualitative - plant material condition, repetitive component failures.

Quantitative - forced outage frequency, turbine runback frequency, safety system availability.

RG&E identified the following issues which they consider to be most significant in resolving their concerns about the staff's proposed indicator.

(1) System and component selection.
(2) Effects of failure (Local versus system versus plant).
(3) "Ghost" Ticks-Remove superfluous "Ghost" ticks.

(4) Multifaceted (other indicators, maintenance team inspections, other inspections).
(5) Individual NPRDS plant reporter expertise and report completeness - Can significantly affect the quality of the NPRDS data.

The following items were identified for future action:

(1) RG&E will prepare a list of equipment, based on their RCM experience, that should be monitored with the staff's indicator.

(2) RG&E will provide the staff access to component data for the systems analyzed to date within the Ginna RCM Program.

RG&E agrees with this summary.

Mark H. Williams, Chief
Trends and Patterns Analysis Branch
Office for Analysis and Evaluation
of Operational Data

Enclosures: As stated.

ENCLOSURE 1

ATTENDANCE LIST

JANUARY 17-18, 1990 MEETING

WITH ROCHESTEP GAS & ELECTRIC CORPORATION

NAME	AFFILIATION
John Fischer	RG&E
Mark Flaherty	RG&E
James Huff	RG&E
Tom Marlow	RG&E
Bob Smith	RG&E
Herb Van Houte	RG&E
Gerald Wahl	RG&E
Joe Widay	RG&E
Bill Zornow	RG&E
Walt Smith	NUMARC
Jim Huzdovich	ATESI
John Wilson	ATESI
Victor Benaroya	NRC/AEOD
Bob Dennig	NRC/AEOD
Pat O'Reilly	NRC/AEOD
Mark Williams	NRC/AEOD

ENCLOSURE 2

AGENDA

JANUARY 17-18, 1990 MEETING WITH ROCHESTER GAS & ELECTRIC CORPORATION

REGARDING MAINTENANCE INDICATORS

(1) NRC presentation - Performance Indicator Development, Analysis Assumptions and Purpose of Meeting.

(2) Discussion of Interim Indicator Results
(3) NPRDS Reporting of Component Failures Involving Outage-Dominating Equipment.
(4) Root Cause Analysis of Individual Component Failures of Outage-Dominating Equipment.

(5) Discussion of RG&E's Programs/Approaches for Trending Equipment Failures and Failure Causes as They Relate to Maintenance

(6) Comparison of Maintenance Trend Information

    (a) Trends Calculated with the NRC's Indicator
    (b) Trends Calculated with RG&E's Indicator(s)

ENCLOSURE 3

RG&E AGENDA FOR MAINTENANCE

INDICATOR DEVELOPMENT MEETING

Introduction	(Marlow)
NRC Presentation of Agenda Items 1-4	
1) RG&E Assessment of NRC Data	
a) RG&E mathematical verification.	(Zornow)
b) 57 reports.	(Zornow)
2) Analysis of Validity of MEI	(Marlow)
a) Concerns with MEI data.	(Marlow)
b) Example of a specific Ginna system which had ticks - CVCS.	(Wahl)
c) Matrix.	(Marlow)
d) Present graphs, charts.	(Marlow)
(5) Discussion of RG&E's Programs/Approaches for Trending Equipment Failures and Failure Causes as They Relate to Maintenance	
a) RCM system selection vs. MEI system selection.	(Wilson)
b) RCM analysis and RCM task evaluation.	(Wilson)
c) RCM Living Program - Tells if we did not have the right system, critical component, dominant failure modes, or frequency.	(Wilson)
(6) Comparison of Maintenance Trend Information	
(a) Trends calculated with the NRC's proposed indicator.	
(b) Trends calculated with RG&E's indicator.	
RG&E's Recommendation for an MEI	(Marlow)
a) Qualitative.	
b) Quantitative.	
Conclusions	(Marlow)

MEMORANDUM FOR: Thomas M. Novak, Director
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

FROM: Mark H. Williams, Chief
Trends and Patterns Analysis Branch
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

SUBJECT: SUMMARY OF FEBRUARY 20-21, 1990 MEETING WITH SYSTEMS ENERGY RESOURCES, INCORPORATED REGARDING MAINTENANCE INDICATOR DEVELOPMENT

On February 20-21, 1990, members of the NRC staff met with representatives of Systems Energy Resources, Incorporated (SERI), the licensee for the Grand Gulf plant, and the Nuclear Management and Resources Council (NUMARC) at the Grand Gulf site to discuss maintenance indicator development. A list of meeting attendees is contained in Enclosure 1. Enclosure 2 contains the meeting agenda.

This meeting was a followup to the October 13, 1989 meeting of the NRC/Industry Maintenance Indicator Demonstration Project.

The NRC staff presented their proposed Maintenance Indicator (MI). The purpose of this presentation was to familiarize utility personnel with all of the detail necessary for understanding the proposed indicator.

Two unique programs at Grand Gulf are particularly relevant to the work on the Demonstration Project. They are the Engineering Review Group (ERG) and the NPRDS Trend Report, both of which are discussed in detail below.

An Engineering Review Group has been formed within the Grand Gulf Performance and System Engineering Department to perform a final, independent review of work orders prior to closeout. Grand Gulf management has tasked this group with ensuring work orders reflect adequate details of the identified problem, including the overall work scope, cause, corrective actions taken, and component failures. The ERG represents a plant improvement with the potential for a direct impact on maintenance indicator development, since one of the concerns expressed about a component failure-based indicator has been the quality of NPRDS reporting. A group such as the ERG provides additional assurance that the failure information documented in the MWOs (and of the subset being reported to the NPRDS) is accurate and complete.

The specific duties of the ERG consist of :

(1) Reviewing completed work orders for consistency,
(2) Obtaining predictive maintenance data for trending,
(3) Providing reports to system engineers for analysis,
(4) Maintaining control of the surveillance tracking program,
(5) Entering all MWOs into SIMS for component failure trending.

The NPRDS Trend Report, which has been prepared and issued periodically since 1987, contains a listing and evaluation of the component failures at Grand Gulf which were entered into the NPRDS database over the previous period. This report: (1) flags repetitive failures, (2) tracks corrective actions, (3) plots the failure rate for components which have experienced major repetitive failures (e.g., radial well pumps, diesel-generator starting air compressor), (4) trends reporting times, and (5) tabulates data for easy reference.

Grand Gulf staff described their maintenance organization and explained their maintenance philosophy. Basically, the responsibility for equipment at the Grand Gulf station is structured around the systems engineering concept. For this reason, they preferred the systems perspective of the NRC's proposed indicator, as opposed to the component type perspective. As far as quality of maintenance is concerned, no distinction is made between safety systems and balance-of-plant systems. The only difference in the maintenance of the two types of systems is that maintenance on safety systems receives a higher priority. Their maintenance program is predicated on the premise that its primary objective is to ensure that the plant operators have available the equipment necessary to operate the plant in a safe manner in accordance with the Technical Specifications. Grand Gulf tries to perform as much of the maintenance tasks as possible during normal plant operation, as opposed to accumulating work for outages. For that work which is performed during a refueling outage, timely closeout of maintenance work during a refueling outage, timely closeout of maintenance work orders (MWOs) and timely reporting to the NPRDS are stressed.

Grand Gulf staff described how the Grand Gulf outage planning and scheduling group interfaces with the regular maintenance organization. Outage planning at Grand Gulf starts as a "seed" that pulls in line management to actually manage the outage. During an outage, the Grand Gulf plant is run by this specially constituted outage organization, and the normal plant organizational lines do not exist during this time. The transition to this outage organization begins about two months before the start of a refueling outage. Following the refueling outage, a formal report is prepared which documents any lessons learned during the outage that can be considered in the planning and scheduling for the next refueling outage. The plant staff stated that they determine whether a refueling outage has been successful from the amount of work completed during the outage and how the plant operates after the outage is completed.

In keeping with the systems perspective, Grand Gulf looks one quarter ahead and tries to consolidate all preventive maintenance (PM) and surveillances for a particular system into, for example, a one-week period, and get all (corrective maintenance, as well as PM) of the work done within this time frame - called a "system outage." The purpose of this approach is to minimize the total time that the system is out of service.

Grand Gulf has actively continued a Maintenance Improvement Program since June 1987. A key element of this program is the installation and implementation of the Station Information Management System (SIMS). This system allows Grand Gulf management the opportunity to closely monitor planned work activities at Grand Gulf. In addition, SIMS provides more space for documenting detailed descriptions of problems and the corrective actions taken. SIMS has the capability for electronically providing the input for NPRDS failure reports. Although this capability is currently not being used, Grand Gulf has future plans to use this system for NPRDS report preparation.

The Grand Gulf staff stated that verbatim compliance with written procedures is stressed at all times with maintenance and operations staff, and personal accountability is emphasized. They

instill a feeling of "ownership" in their operations, maintenance, and engineering support personnel.

Another part of the maintenance philosophy at Grand Gulf is the stated policy that contractors are not employed to perform routine maintenance tasks.

Another key element of the Maintenance Improvement Program at Grand Gulf is its Predictive Maintenance Program. Grand Gulf staff presented a discussion of this program. Basically, it consists of the following:

(1) Vibration monitoring of rotational equipment.
(2) Lube oil analysis program.
(3) Motor-operated valve testing.
(4) Pump and valve testing program.
(5) Local leak rate testing.
(6) Check valve performance monitoring.
(7) Leakage reduction program.
(8) Relief valve testing program.
(9) Scram frequency reduction program.
(10) Human performance evaluation system (HPES).
(11) Plant performance monitoring.
(12) NPRDS.
(13) Erosion/corrosion program.

Consistent with a stated management goal to make Grand Gulf a top performer, SERI has pursued cross-fertilization between Grand Gulf and those U.S. plants, as well as plants outside the U.S., which are considered among the best performing units in the country. This exchange of technical expertise has taken place at all levels of plant management.

Discussion of the results of root cause analyses of a selected set of Grand Gulf NPRDS failure narratives and the indicator trend led to the identification of a number of issues regarding the NRC staff's proposed maintenance indicator.

(1) Grand Gulf staff expressed concern that the indicator can be skewed by just a few problem components and thereby show maintenance problems. The NRC staff pointed out that high maintenance equipment can result in indications, but that the indicator looks across a broad spectrum of equipment and a few problems will not make a plant stand out.

(2) Grand Gulf staff expressed concern about the usage of the staff's proposed indicator. How it will be used and by whom are major concerns which have been voiced in previous project meetings. The NRC staff explained that it would be used by the NRC staff to monitor the industry's progress in maintenance and to provide input to senior management regarding plant performance through the following process. The indicator for a given plant would be compared against the average of its peers, and the indicator trends would also be examined. If a plant's indicator is consistently higher than the peer group average and displays an adverse trend, the plant operational data for the period(s) where the indicator exhibits the unfavorable characteristics would be examined in detail to determine the driving forces behind the component failures experienced during the period. Also, the staff would check into the plant's NPRDS reporting history to determine whether this had

an influence on the indicator. The indicator would be used as a screening tool to trigger a more detailed review of plant data and experience obtainable from many sources (e.g., regional office inspections, maintenance team inspections, diagnostic evaluations, SALPs).

(3) Grand Gulf staff expressed concern about the characterization of the indicator. In this respect, they were concerned that each individual indicating flag, or even each individual component failure, could be construed as a sign of maintenance ineffectiveness. The NRC staff explained that the indicator was designed as a programmatic indicator, and as such, was not intended to track individual events.

(4) Discussion of the failure history for the radial well pumps at Grand Gulf led to identification of a case very similar to that of the charging pumps at San Onofre 2 and 3 (i.e., a case where original design engineering support, and traditional maintenance have played roles over time in the performance of equipment). In the case of the radial well pumps, Grand Gulf staff explained that the pumps have had a history of seal failures, in part caused by suspended mud intake from the river water. As river level varied, so did mud intakes. Over a period of time, systems engineering and maintenance staff have formulated an improved maintenance approach, employing PM to "get ahead" of the failures as much as possible, and they expect the pump failure rate to decrease, at which point the proposed indicator would reflect improved performance resulting from a maintenance program improvement. They also plan to erect a building over the pumps to protect them from the elements and facilitate detection of seal failures at the incipient stage. Extensive maintenance had not coped with detecting early failures in the past. However, they pointed out that some random pump failure rate will persist due to "bursts" of sediment in the wells. Complicating the situation is the fact that, at certain times of the year, work cannot be performed on the pumps because of the danger to personnel from the high level of the Mississippi River. Therefore, the Grand Gulf staff was concerned that individual failures of this nature would be considered as caused by ineffective maintenance, and that some failure rate would always be present, since cost-benefit would not support a zero-failure approach to this problem.

The NRC staff explained that for these pumps, the way to demonstrate improvement in the maintenance process was to track the failures before and after those improvements. In this sense, the failures are related to maintenance, especially within the broad context of the Commission's policy statement. Individual failures are also filtered through the indicator algorithm, which tends to screen random failures. However, the staff is exploring additional ways to address the existence of a residual inherent failure rate, such as the use of a tolerance band around the indicator trend.

(5) Discussion of the failure narratives associated with the Grand Gulf LPRM system led to identification of another similar case. In this situation, the LPRM detectors (which are the first of a kind and unique to the BWR/6 design) were failing with an NPRDS failure description of "out of calibration," and a cause category of "dirty connections." The Grand Gulf staff explained that this condition was not caused by dirty connections as indicated, but actually was a design peculiarity unique to these specific detectors. The detectors were not field repairable, since the internals were not accessible. After much interaction between the NSSS vendor and SERI, it was found that the root cause of the detector going out of calibration was a buildup on the internal connections in the instrument. The corrective action recommended for the problem was a capacitive discharge test which would burn off the buildup on the connections. Since there was no way to anticipate this

type of failure, the Grand Gulf staff eventually implemented a PM task that performs the test before the performance of the instrument progresses to the degraded stage. Grand Gulf staff maintained that failures of this type should not be tracked by the indicator since there was no way that the first failure of the detectors could have been prevented, and then the uniqueness of the design and inaccessibility of the detector internals made it impossible to perform any sort of preventive maintenance until a failure history of the instruments could be compiled over a long enough span of time upon which to base appropriate PM.

(6) A number of cases were discussed which consisted of the reporting of incipient conditions as degraded failures. The Grand Gulf staff explained that past NPRDS reporting practices may have been somewhat conservative, and commented that incipients would today be recognized and categorized more readily.

(7) "Ghost ticks" should be eliminated.

The Grand Gulf staff uses the following activities and documents at the frequency indicated to assess maintenance at the Grand Gulf plant.

Daily

(1) Plant Status Report.
(2) Plant Tours to monitor maintenance activities and housekeeping/plant material conditions.

Weekly

(1) Work Order Status Report.
(2) Plant Contamination Report.
(3) Maintenance Task Tracking.
(4) Quality Deficiency Status Report.
(5) Material Nonconformance Report.

Monthly

(1) Maintenance Performance Report.
(2) Performance Monitoring Report.
(3) Thermal Performance Report.
(4) Operational Analysis Report.
(5) Health Physics Summary Report.

Quarterly

(1) Quality Programs Status and Trend Analysis Report.
(2) NPRDS Trend Report.

Of particular interest is the Maintenance Performance Report, which is issued on a monthly basis, and is made available to all maintenance personnel for their review. This report tracks the following maintenance-related information: (1) maintenance goals versus actual achievements, (2) major work items during the month, (3) safety report, (4) occupational injury and illness, (5)

LERs, (6) violations, (7) radiological deficiency reports, (8) personnel contamination report with details, (9) personnel exposure, (10) quality deficiency reports, (11) security response to insecure doors, (12) maintenance outages, (13) maintenance work status, (14) task tracking, (15) department overtime, and (16) budget.

Mark H. Williams, Chief
Trends and Patterns Analysis Branch
Office for Analysis and Evaluation
of Operational Data

Enclosures: As stated

ENCLOSURE 1

ATTENDANCE LIST

FEBRUARY 20-21, 1990 MEETING

WITH SYSTEMS ENERGY RESOURCES, INCORPORATED

NAME	AFFILIATION
Bill Angle	SERI
W. T. Cottle	SERI
Joel P. Dimmette, Jr.	SERI
Chuck Dugger	SERI
Norman G. Ford	SERI
Randy Hutchinson	SERI
M. A. Krupa	SERI
Ron Moomaw	SERI
Jerry C. Roberts	SERI
Steve Saunders	SERI
Warren J. Hall	SERI
H. O. Christensen	NRC/RII-SRI
Bob Dennig	NRC/AEOD
J. L. Mathis	NRC/RII-RI
T. M. Novak	NRC/AEOD
Patrick O'Reilly	NRC/AEOD
Mark Williams	NRC/AEOD

ENCLOSURE 2

AGENDA

FEBRUARY 20-21, 1990 MEETING WITH SYSTEM ENERGY RESOURCES, INCORPORATED

REGARDING MAINTENANCE INDICATORS

(1) NRC presentation - Performance Indicator Development, Analysis Assumptions and Purpose of Meeting.

(2) Discussion of Interim Indicator Results
(3) NPRDS Reporting of Component Failures Involving Outage-Dominating Equipment.
(4) Root Cause Analysis of Individual Component Failures of Outage-Dominating Equipment.

(5) Discussion of SERI's Programs/Approaches for Trending Equipment Failures and Failure Causes as They Relate to Maintenance

(6) Comparison of Maintenance Trend Information

(a) Trends Calculated with the NRC's Indicator
(b) Trends Calculated with SERI's Indicator(s)

MEMORANDUM FOR: Thomas M. Novak, Director
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

FROM: Mark H. Williams, Chief
Trends and Patterns Analysis Branch
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

SUBJECT: SUMMARY OF FEBRUARY 28 - MARCH 1, 1990 MEETING WITH NORTHEAST UTILITIES REGARDING MAINTENANCE INDICATOR DEVELOPMENT

On February 28 - March 1, 1990, staff from AEOD, Northeast Utilities (NU), NU's operating companies, and NUMARC met at the Northeast Utilities offices in Berlin, Connecticut to exchange information on maintenance indicators. This meeting was part of the NRC/Industry Maintenance Indicator Demonstration Project. A list of meeting attendees is contained in Enclosure 1. Enclosure 2 provides the meeting agenda. On March 1, 1990, the staff also toured the Haddam Neck nuclear plant.

The NRC staff presented the detail and logic which were followed during the development of the staff's proposed maintenance indicator (MI). The purpose of this presentation was to familiarize utility personnel with all of the detail necessary for understanding the proposed indicator.

In their opening remarks, NU discussed their management approach for the Millstone and Haddam Neck sites. Each unit at each site is operated as an independent entity under the direction of the unit superintendent. Within this framework of independence, each unit has its own maintenance staff and facilities, and tracks cents per kilowatt at the bus bar. However, certain major aspects of the maintenance policy are established at the corporate level. For example, it is NU's policy that their nuclear plants are not allowed to enter a limiting condition for operation (LCO) solely for the purpose of performing planned maintenance. NU also has established a system-wide Production Maintenance Management System, or PMMS.

PMMS, which was first placed into operation almost ten years ago on a phased implementation basis, is now almost completely implemented, and is used to track maintenance at all of their electrical generating stations, fossil as well as nuclear. It is a computerized maintenance tracking system with fairly extensive capabilities. NU has used PMMS to: (1) identify plant equipment by means of a system-wide common nomenclature, (2) establish a dedicated planning function at each of their generating facilities, (3) establish a common maintenance work order mechanism across facilities (4) provide a uniform work priority system, (5) provide resource forecasting and tracking on a consistent system-wide basis, and (6) provide a database of production-related information in support of management decisions.

There is an important difference between PMMS and the staff's proposed indicator. PMMS tracks work orders and associated information. The staff's proposed indicator tracks equipment failures. In order to extract failure data from PMMS, engineering analysis supported by standardized guidance, such as found in NPRDS, is required.

NU employs PMMS to generate the PMMS Performance Report on a quarterly basis. This report trends a number of indicators which NU uses to monitor maintenance performance at their plants. The contents of the PMMS Performance Report are as follows: (1) Preventive Maintenance Percentage, (2) Corrective Maintenance Backlog, (3) CM Backlog Indicator, (4) Preventive Maintenance Performance, (5) Twenty Most Worked on Components, (6) Ten Most Worked on Systems, and (7) Rework Percentage. Performance Indicators have been used in the NU organization as management tools for about five years.

NU considers Items (1), (3), and (7) above their primary maintenance indicators. The Preventive Maintenance Percentage displays a trend of the preventive work accomplished by a task department as a percentage of the total maintenance work. The CM Backlog Indicator is an indicator which was developed internally by NU. This indicator displays a curve of CM work that indicates the condition of the work backlog and the clearing rate time constant. This consists of the number of priority 3 non-outage CM work orders that are open at a point in time. This process indicator is not used to provide diagnostic feedback to the organization at the working level. The Rework Percentage displays a trend of CM and other work orders that failed a retest by operations by quarter.

NU also produces a quarterly Utility Performance Report for NU management which contains (1) capacity factor, (2) forced outage rate, (3) thermal performance (unit heat rate), (4) LERs, (5) unplanned automatic reactor trips, (6) plant design change evaluation status, (7) plant design change request status, (8) solid radioactive waste generated, (9) collective man-rem exposure, (10) total skin and clothing contaminations, (11) PMMS Indicators #1 and #3, (12) NRC inspections - violations and severity level, (13) outstanding INPO recommendations, (15) NE&O contractors, and (16) Enforcement conferences.

During a discussion about maintenance during outages, NU stated that each of its four units (Haddam Neck, Millstone Units 1,2, and 3) prepares an outage report 30-60 days after the completion of a refueling outage which documents lessons learned during the outage. Within the NU organization, outage planning is done on a unit level, as opposed to the corporate level. Usage of the NPRDS database by the NU organization was also discussed. Currently, there is a task force within the organization evaluating how NPRDS could best be used to enhance plant operations. In the past, the NU organization has not used NPRDS data very much, and since it is prepared at the corporate level, unit maintenance managers are generally not familiar with the NPRDS data for their units.

Prior to the meeting NU was provided with examples of NPRDS-reported failures, used in constructing the proposed indicator, that the staff categorized as maintenance-related. The discussion of the history behind these failures indicated that plant staff were aware of component performance problems and had often made various adjustments to the maintenance programs in response. However, the utility determination that the performance problem originated in a marginal application of a component design resulted in their concluding that the failures were not related to maintenance. Several examples are discussed below. Since the frequency of such failures is being controlled by the maintenance program, the staff believes an increase or decrease in such failures is a measure of maintenance effectiveness.

There were a number of failures of a reactor recirculation pump pressure switch at Millstone 1 that the utility had attributed to wearout in the NPRDS failure records. On other occasions, the same switch had drifted out of specification due to unknown causes. The NU staff explained

that this particular switch was a design problem that had existed since the plant was built. It was essentially a misapplication of design which utility management had made a decision to live with, and had charged the maintenance department to keep the equipment operating, given this deficiency. NU stated that a temporary solution to the problem had been implemented. This consisted of an increased surveillance frequency which was established to catch the instrument drift while it was still in the incipient stage before the instrument's function became degraded.

Another example consisted of three failures of main feedwater pump seals at Millstone 3. In this case, according to the utility, the original pump seal design was marginal, especially at low flow conditions, when flashing led to overheating of the seal and subsequent failure. As explained, this was a misapplication of design, for which utility management had decided that continuing to fix seal failures was more cost-effective than making a major design modification. The maintenance organization was then faced with the responsibility of keeping the pumps in operating condition in spite of the seal problem. These failures were either categorized as due to unknown causes or attributed to design problems.

During the meeting, NU staff expressed a number of concerns about the usefulness of the proposed indicator. The need for resources to respond to another indicator (fielding questions from the NRC and various PUCs), with the likely outcome that these resources would be diverted from existing staff now devoted to utility performance trending, was a major concern. In the NRC staff's view, the intended use of the proposed indicator should help allay this concern. The utility staff also felt that the proposed indicator was difficult to interpret, and offered little diagnostic information for corrective action. As a programmatic indicator, diagnostic capability was not a prime concern originally, but comments from other Demonstration Project participants have resulted in modifications, such as cutting the indicator by component type, to enhance its usefulness to plant staff.

The utility staff also felt that the quality of NPRDS reporting may not be high enough for this important use. The tendency for NPRDS data to show concentrations of failures discovered in outages, and the potential for penalizing proactive maintenance if incipient conditions were reported as degraded failures were raised as issues. NRC staff actions to adjust indicator interpretation based on various segments of the fuel cycle, and examination of reporting patterns in interpreting the indicator were cited by the staff as potential remedies for these concerns.

Lastly, NU staff were concerned about use of a single indicator to track maintenance. the staff explained that no indicator is used in the absence of other information, including other indicators and information from various types of inspections. Further, the proposed indicator was developed as an example of the type of indicator needed, and was not intended to be the only indicator based on component failure data.

Mark H. Williams, Chief
Trends and Patterns Analysis Branch
Office for Analysis and Evaluation
of Operational Data

Enclosure: As stated

ENCLOSURE 1

ATTENDANCE LIST

FEBRUARY 28-MARCH 1, 1990 MEETING

WITH NORTHEAST UTILITIES

NAME	AFFILIATION
Bob Dennig	NRC/AEOD
T. M. Novak	NRC/AEOD
Patrick O'Reilly	NRC/AEOD
Mark Williams	NRC/AEOD
Thomas Laats	EG&G-Idaho
Howard Stromberg	EG&G-Idaho
Peter M. Austin	Northeast Utilities
Mike Ciccone	Northeast Utilities
Tom Dente	Northeast Utilities
Neil Herzig	Northeast Utilities
William J. Nadeau	Northeast Utilities
Wayne D. Romberg	Northeast Utilities
Jere LaPlatney	Connecticut Yankee Atomic Power Company
Neil Bergh	Northeast Nuclear Energy Company
Peter J. Przekop	Northeast Nuclear Energy Company
Ron Rothgeb	Northeast Nuclear Energy Company
Walt Smith	NUMARC
Tom Tipton	NUMARC

ENCLOSURE 2

AGENDA

FEBRUARY 28-MARCH 1, 1990 MEETING WITH NORTHEAST UTILITIES

REGARDING MAINTENANCE INDICATORS

(1) NRC presentation - Performance Indicator Development, Analysis Assumptions and Purpose of Meeting.

(2) Discussion of Interim Indicator Results

(3) NPRDS Reporting of Component Failures Involving Outage-Dominating Equipment.

(4) Root Cause Analysis of Individual Component Failures of Outage-Dominating Equipment.

(5) Discussion of Northeast Utilities' Programs/Approaches for Trending Equipment Failures and Failure Causes as They Relate to Maintenance

(6) Comparison of Maintenance Trend Information

  (a) Trends Calculated with the NRC's Indicator
  (b) Trends Calculated with Northeast Utilities' Indicator(s)

APPENDIX B

MAINTENANCE INDICATOR DEMONSTRATION PROJECT DETAILS

This Appendix discusses the details of a typical meeting with one of the utility participants in the Demonstration Project. It also contains a roster of all the utility staff and consultants that participated in these meetings, along with copies of the NRC standard presentation slides used during each of these individual meetings.

APPENDIX B

MAINTENANCE INDICATOR DEMONSTRATION PROJECT DETAILS

The second meeting of the NRC/Industry Maintenance Indicator Demonstration Project took place on October 13, 1989. At this meeting, each of the six project utility-participants presented their preliminary comments regarding the NRC staff's proposed Maintenance Indicator and summarized the results of their reviews of the plant-specific set of NPRDS component failures which the NRC staff had provided to each utility-participant at the first meeting of the project on September 12, 1989. In order to obtain more details concerning each utility's review, the NRC staff held a series of two-day meetings with each of the six project utility-participants over the five-month period November 1989-March 1990. These meetings were held either at the utility's headquarters office or at one of the utility's plant sites. Table B-1 shows the date and location for each of the six meetings. Prior to each of the six meetings, the NRC staff sent a letter to the senior management of the respective utility-participant acknowledging the meeting date and transmitting a proposed agenda for the meeting. To ensure consistency in the information discussed during the meetings, a standard agenda was used for the series of six meetings. Table B-2 contains the standard meeting agenda. Table B-3 identifies the participating utility staff and consultants who participated in these six meetings.

Typically, each meeting began with introductory remarks by the utility's Senior Vice President - Nuclear or his designated representative. The NRC staff then gave a detailed presentation on the development and validation of the staff's proposed Maintenance Indicator. Using a standard set of slides (Table B.4), the NRC staff described the proposed indicator concept, explained how the indicator was constructed, discussed the indicator validation process, and for illustrative purposes, presented the indicator for a typical plant. The staff's presentation was designed to familiarize utility personnel with all of the details necessary for understanding the indicator.

Next, the NRC staff presented the indicator for the utility's plants. In the discussion that ensued, the NRC staff related to the utility staff their interpretation of the specific plant's indicator; whether the indicator for the plant was higher than, below the average, or average relative to the average for that plant's peer group, and whether any adverse trends in the indicator were noted. In turn, the utility staff provided their comments on the proposed indicator based on their review of the failure data which were monitored by the indicator. This discussion of the indicator was usually followed by a discussion of the NPRDS - the utility's NPRDS reporting philosophy (tendency to over report vs. under reporting), how the reporting is handled (on a unit basis or at the corporate level), and who determines what information from the work orders is reported to NPRDS.

The NRC staff and the utility staff then embarked on a detailed discussion of the root cause of a specific group of NPRDS failure records that contributed to the indicating flags generated by the NRC staff's proposed indicator. A sample set of failures used in this discussion is shown in Table B.5. The records discussed consisted of failures which the utility had categorized as attributable to causes other than maintenance (e.g., engineering/design, wearout, unknown, random failure), but the NRC staff, applying the scope of the Commission's definition of maintenance as specified in its Revised Maintenance Policy Statement issued December 4, 1989, had classified as maintenance-related. Generally, the staff's review of the NPRDS failure narratives for the records in question had resulted in about 70-80% of the failures reviewed being ascribed to maintenance. In contrast, the utility's review of the same set of failure records, using all of the detailed information about the

individual failures at the utility's disposal and applying the industry's much narrower view of the definition of maintenance, usually resulted in a much smaller percentage (5-15%) being characterized as maintenance-related. Typically, the majority of the failures were attributed to wearout or to unknown causes.

Out of these discussions arose issues such as whether first failures or failures of components that had been in service for relatively long periods of time should be classified as maintenance-related. Another issue that was identified during these discussions was whether the failure of a problem component for which a management decision had been made to continue to maintain the component in operable condition as opposed to implementing a major (and, therefore expensive) design modification (e.g., the charging pumps at San Onofre 2 and 3) should be captured as a maintenance-related failure.

A related issue which originated from these discussions was the discovery that, in the interest of conservatism, most of the utilities in some cases had reported what were apparently incipient conditions as degraded failures. Such over reporting would have a direct adverse effect on the NRC staff's proposed indicator, since the indicator was originally designed to consider only degraded and immediate failures, not incipient conditions.

These discussions enabled each of the two parties to better understand the other's perspective of maintenance. Sometimes the utility staff changed their position on a given failure, and agreed with the NRC staff that the failure was maintenance-related. In other cases, the NRC staff agreed with the utility's position. The end result of these discussions was generally that the percentage of the total number of failures attributed to maintenance-related causes might change by as much as 10%. However, as far as the NRC staff was concerned, the majority of the component failures that comprised the indicator was still maintenance-related, and their original conclusion on this issue was still valid.

The utility staff then discussed their programs for monitoring trends in maintenance. For the most part, these consisted of plant level performance indicators which track the maintenance process (termed process indicators in AEOD/S804A and S804B). Included in this category are the three INPO performance indicators that are related to maintenance. These are Corrective Maintenance Backlog, Ratio of Preventive Maintenance to Total Maintenance, and Percentage of Preventive Maintenance Missed. Some utilities track these indicators in a separate formal report which the plant staff prepares for senior management on a regular basis. Other utilities include the maintenance-related indicators in the overall plant performance indicator report that is issued periodically to management. One utility has developed its own maintenance indicator which it tracks in a special maintenance performance report that is issued on a periodic basis. Another utility did not have any formal report which tracked maintenance indicators.

Finally, the last item on the meeting agenda was a comparison of maintenance trend information calculated with the NRC staff's proposed indicator and the maintenance trend information calculated with the utility's indicator(s). In this case, the only available trend information was that provided by the NRC staff's proposed indicator. None of the utilities visited have a programmatic indicator that is used to routinely monitor equipment performance and feed back that information to the organization at the working level. Consequently, the only discussions which took place with each utility regarding this agenda item were primarily qualitative.

Following all of the meetings except one, the NRC staff was given a tour of the plant site conducted by the utility staff.

Table B-1

NRC Staff Meetings with Individual Project Utility-Participants

Meeting Dates	Project Utility-Participant	Meeting Location
11/29-11/30/89	Commonwealth Edison Company	Commonwealth Edison Office - Chicago, IL
12/12-12/13/89	Southern California Edison Company	San Onofre Plant Site
01/09-01/10/90	Duke Power Company	Oconee Plant Site
01/18-01/19/90	Rochester Gas and Electric Corporation	Ginna Plant Site
02/20-02/21/90	Systems Energy Resources, Inc.	Grand Gulf Plant Site
02/28-03/01/90	Northeast Utilities	Northeast Utilities Office - Berlin, CT

Table B-2

Agenda Used in Meetings with Six Project Utility-Participants

(1) NRC Presentation - Performance Indicator Development, Analysis Assumptions and Purpose of Meeting.

(2) Discussion of Interim Indicator Results.

(3) NPRDS Reporting of Component Failures Involving Outage-Dominating Equipment.

(4) Root Cause Analysis of Individual Component Failures of Outage-Dominating Equipment.

(5) Discussion of Project Utility-Participant's Programs/Approaches for Trending Equipment Failures and Failure Causes as They Relate to Maintenance.

(6) Comparison of Maintenance Trend Information.

(a) Trends Calculated with the NRC's Indicator.
(b) Trends Calculated with the Utility-Participant's Indicator(s).

Table B-3

Utility Staff and Consultants Participating in Demonstration Project Meetings

Name	Affiliation
Jere LaPlatney	Connecticut Yankee Atomic Power Company
Ron Rothgeb	Northeast Nuclear Energy Company
Neil Bergh	Northeast Nuclear Energy Company
Peter J. Przekop	Northeast Nuclear Energy Company
Tom Dente	Northeast Utilities
Mike Chiccone	Northeast Utilities
Neil Herzig	Northeast Utilities
Peter Austin	Northeast Utilities
William Nadeau	Northeast Utilities
Wayne Romberg	Northeast Utilities
Paul Kuhel	Commonwealth Edison Company
Martin G. Kief	Commonwealth Edison Company
Don Eggett	Commonwealth Edison Company
Robert Lazon	Commonwealth Edison Company
Thomas Kovach	Commonwealth Edison Company
Lee A. Sues	Commonwealth Edison Company
Brian Katz	Southern California Edison Company
Don Evans	Southern California Edison Company
Ralph Sanders	Southern California Edison Company
Robin Baker	Southern California Edison Company
L. D. Brevig	Southern California Edison Company
Fred Briggs	Southern California Edison Company
Jack Rainsberry	Southern California Edison Company
Loyd Wright	Southern California Edison Company
R. H. Bridenbecker	Southern California Edison Company
Harold Ray	Southern California Edison Company
M. E. Rodin	Southern California Edison Company
Barbara Aden	Southern California Edison Company
Bob Levine	Southern California Edison Company
Wayne Hallman	Duke Power Company
Bill Foster	Duke Power Company
Ronnie Henderson	Duke Power Company
Sam Hamrick	Duke Power Company
Stuart Lindsey	Duke Power Company
Dendy Clardy	Duke Power Company
Bill Angle	Systems Energy Resources, Incorporated
W. T. Cottle	Systems Energy Resources, Incorporated
Joel P. Dimmette, Jr.	Systems Energy Resources, Incorporated
Chuck Dugger	Systems Energy Resources, Incorporated
Norman G. Ford	Systems Energy Resources, Incorporated
Randy Hutchinson	Systems Energy Resources, Incorporated
M. A. Krupa	Systems Energy Resources, Incorporated
Ron Moomaw	Systems Energy Resources, Incorporated
Jerry Roberts	Systems Energy Resources, Incorporated
Steve Sanders	Systems Energy Resources, Incorporated

Table B-3 (Continued)

Utility Staff and Consultants Participating in Demonstration Project Meetings

Name	Affiliation
John Fischer	Rochester Gas & Electric Corporation
Mark Flaherty	Rochester Gas & Electric Corporation
James Huff	Rochester Gas & Electric Corporation
Bob Smith	Rochester Gas & Electric Corporation
Tom Marlow	Rochester Gas & Electric Corporation
Herb Van Houte	Rochester Gas & Electric Corporation
Gerald Wahl	Rochester Gas & Electric Corporation
Joe Widay	Rochester Gas & Electric Corporation
Bill Zornow	Rochester Gas & Electric Corporation
Jim Huzdovich	ATESI
John Wilson	ATESI

Table B.4

NRC Standard Presentation Slides

Slide No.	Subject
1	Current Indicators - Simple List
2	P. I. Report page - Finger Charts
3	P. I. Report page - Trend Charts
4	P. I. Report page - Part II event descriptions
5	Commission Direction on Maintenance PIs - Background
6	LER Causes & Corrective Actions - Ind. Avg. w/maintenance
7	MEI Summary Description - Failure rate increase with causes
8	MEI Trend - totals of prior slide portrayed over time for a plant
9	ODE Equipment Selection Basis
10	MEI ODE Systems Selected
11	Key Aspects of the Indicator
12	Indicator Display candidate (with cumulative curve)
13	Validation Activities
14	MEI vs. Cause Code Correlation
15	MEI BWR & PWR Populations (2 yr. totals)
16	MEI Trend for PWRs (2 yr. regression line)
17	Demonstration Project Background
18	Demonstration Project - Utility membership

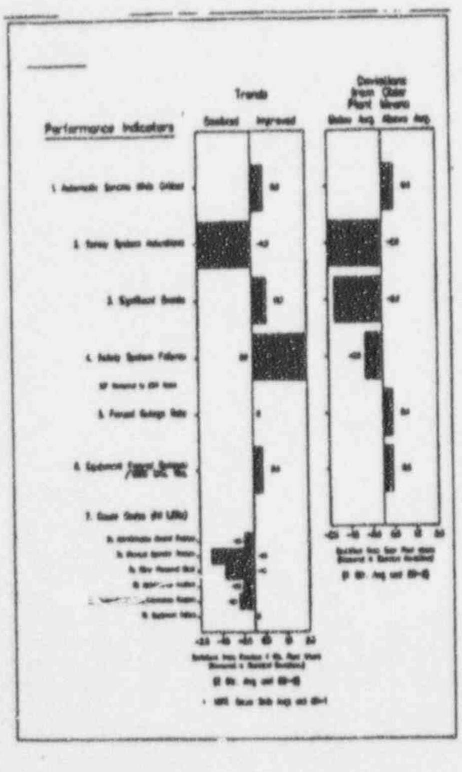
Slide 1

CURRENT INDICATORS

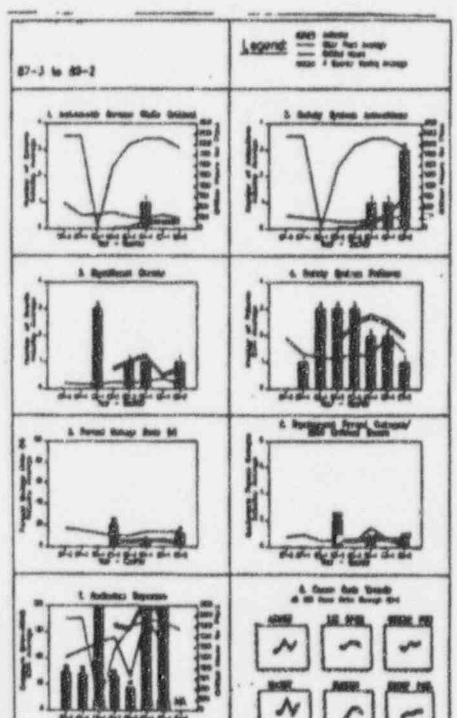
- Automatic Scrams While Critical
- Safety Systems Actuations
- Significant Events
- Safety System Failures
- Forced Outage Rates
- Equipment Forced Outages/1000 Crit. Hrs.
- Collective Radiation Exposure*
- Cause Codes

*Provided by INPO

Slide 2



Slide 3



Slide 4

[illegible]

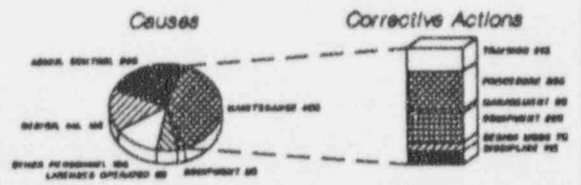
Slide 5

MAINTENANCE MONITORING

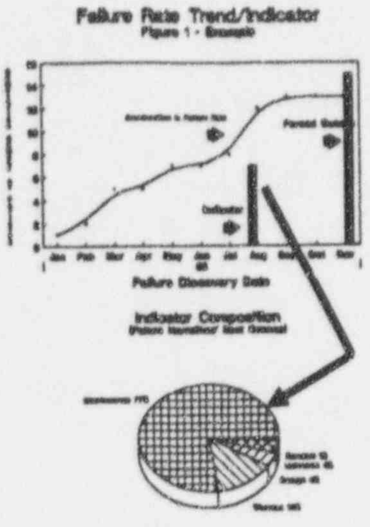
- COMMISSION DIRECTION - MAINTENANCE INDICATORS
  - AEOD S804A-Process Indicators (10/89)
  - AEOD S804B-Effectiveness Indicators (2/90)
  - Follow-up development
- MAINTENANCE RULEMAKING ASSOCIATION
  - Monitor and Inspection Function
  - Regulatory Guide and Policy Statement
- 18 MONTH INTERVAL
  - Maintenance Indicator Use
  - Staff Evaluation
- INTERACTION WITH INDUSTRY
  - Commission Intent

Slide 6

CORRECTIVE ACTIONS
EVENTS WITH MAINTENANCE CAUSES



Slide 7



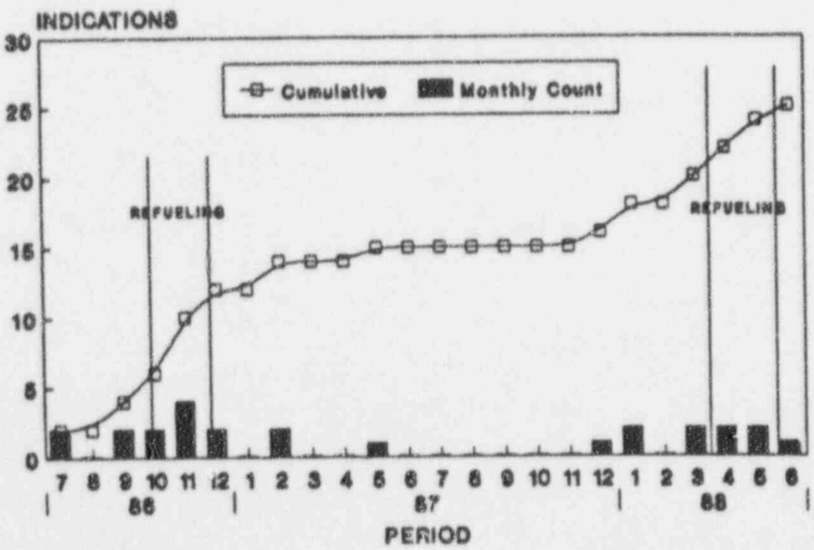
Maintenance Effectiveness Monitoring

Office for the Analysis and Evaluation of Operational Data

U.S. Nuclear Regulatory Commission

Slide 8

MAINTENANCE EFFECTIVENESS INDICATOR (TREND)



Slide 9

ODE SYSTEM AND COMPONENT SELECTION

- SYSTEM AND COMPONENT SELECTION
  - 10 to 12 systems per plant per vendor
  - 500 to 2000 components per plant
  - 28 to 31 percent of reportable components per vendor
- LIST COMPARED AGAINST
  - NUREG-0020 (Gray Book)
  - Stoller report
  - NERC report

Slide 10

MEI SYSTEMS MONITORED

BWR	PWR
Reactor Recirculation	Reactor Coolant
Reactor Protection	Reactor Protection
Control Rod Drive	Control Rod Drive
Condensate	Condensate
Feedwater	Feedwater - Main, Auxiliary/Emergency
Main Steam	Main Steam
Nuclear Steam Supply Shutoff - Valves, Rod. Man., etc.	
Essential Service Water	
Plant AC Power Distribution	Plant AC Power Distribution
Instrument AC Power	Instrument AC Power
	Charging Subsystem

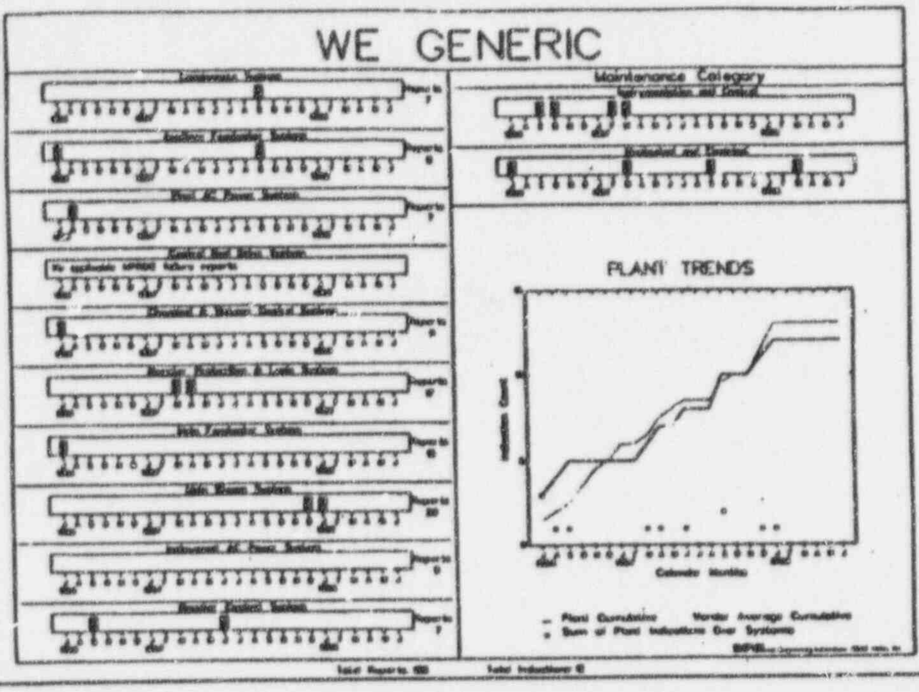
Slide 11

MAINTENANCE EFFECTIVENESS INDICATOR (KEY ASPECTS)

- NORMALIZED TO PLANT REPORTING PRACTICES
  - Not absolute value
    (Not detrimental to high reporting)
- MONITORING WITHIN SYSTEM ON A MONTHLY BASIS IS ESSENTIAL
- CONSTRUCTED TO CREATE A RELATIVELY COMPLETE DATA SET FOR VALIDATION
  - Discussions with plant NPRDS coordinators
  - Equipment selection criterion
    (Major components important to power generation in NPRDS scope (historical))
  - Incipient failures not included
    (Reduced reporting variability)
    (Allows plants to monitor more closely)
- OTHER SYSTEMS AMENABLE TO SAME APPROACH

Slide 12

EXAMPLE MEI DISPLAY

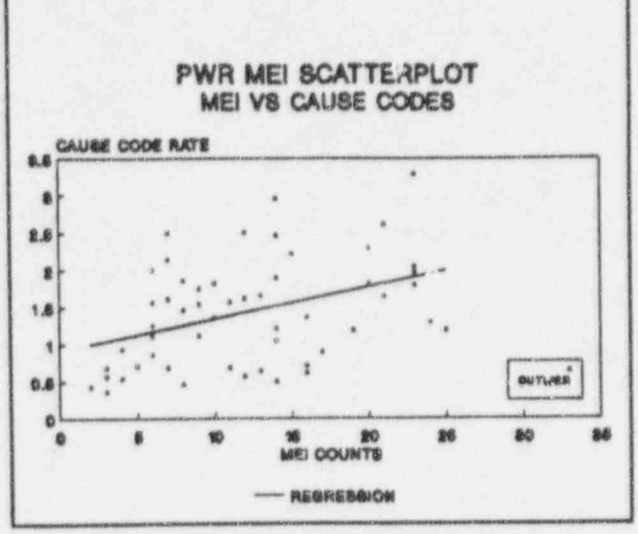


Slide 13

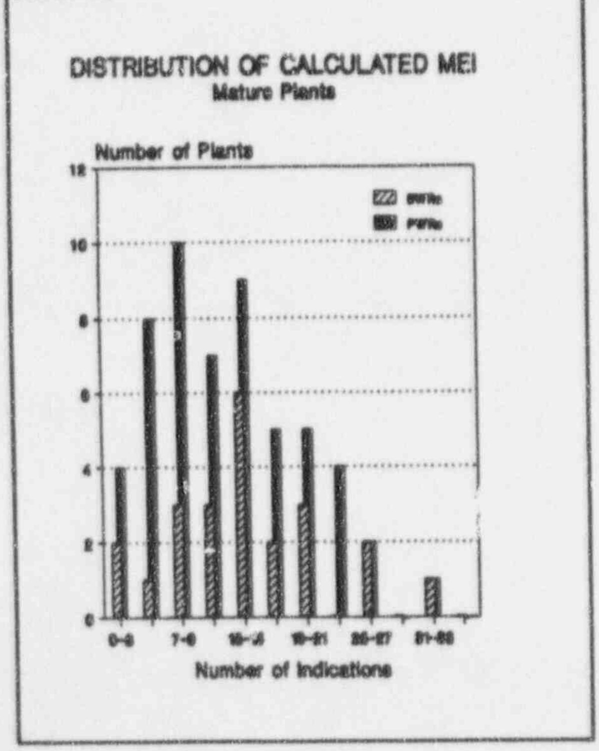
VALIDATION ACTIVITIES

- ROOT-CAUSE ANALYSIS
- LER CORRELATION ANALYSIS
- INSPECTION REPORT ANALYSIS
- OTHER CORRELATION ANLYSES
  - Time Lag
- CORRELATIONS WITH OTHER [illegible]
  - FRV
  - MFP

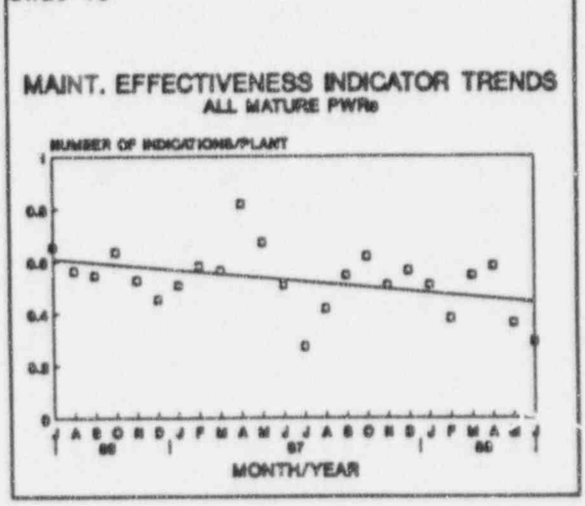
Slide 14



Slide 15



Slide 16



Slide 17

NRC/UTILITY DEMONSTRATION PROJECT

- INDUSTRY MEETINGS
  - Initial meeting - July 19, 1989

    NUMARC agreement on coordination
  - Task Group meeting - September 12, 1989

    AEOD presents results and provides plant-specific data.
  - October 13, 1989 - Industry feedback issues - Definitions and Reporting
  - Utility Visits - Trend Comparison and evaluation issues in controversy
  - Schedule - Development Completion - 3/90

Slide 18

DEMONSTRATION PROJECT

- INDUSTRY MEMBERSHIP

  Commonwealth Edison

  Duke Power

  Mississippi Power & Light

  Northeast Utilities

  Rochester Gas & Electric

  Southern California Edison

  INPO

  NUMARC

Table B.5

Examples: Failure Narratives Categorized as Maintenance

1. **Event:** CVCS boric acid blender control isolation valve failure
Discovery Date: 9/4/87
Cause Cat.: Unknown
Cause Desc.: Normal/Abnormal Wear; Corrosion

Narrative: The boric acid to boric acid blender control isolation valve was found not fully closed after conducting a procedure. The unit was being cooled down. The valve internals were heavily corroded and eroded. WR 131670. The seat ring, gasket, and bonnet were replaced. Reassembled and tested the valve for proper operation.

Comment: This valve had a previous failure [illegible]9/87 when the valve plug was discovered broken off and the valve seat was badly eroded; then the plug assembly, seat ring, and cage were replaced.

2. **Event:** CVCS seal water injection filter inlet isolation valve failure
Discovery Date: 11/14/87
Cause Cat.: Unknown
Cause Desc.: Out of Mechanical Adjustment; Previous Repair/Installation Status

Narrative: Seal water injection filter 1A inlet isolation valve was leaking. It was found by an operator while the unit was coming up in power after a refueling outage. The valve diaphragm was crushed and the valve disc had wrong measurements; the root cause was unknown. The disc and valve diaphragm were replaced; the valve was reassembled, and proper operation and no leakage were verified. (WR 132654)

Comment: The cause description associates this failure with previous repair.

3. **Event:** CVCS charging flow control valve operator failure
Discovery Date: 3/22/87
Cause Cat.: Unknown
Cause Desc.: Out of Calibration

Narrative: Chemical and Volume Control charging flow control valve was swinging when pump "A" was placed into service. The valve stabilized when pump "B" was placed into service. The unit was at full power. The cause was improper adjustment of the gain on the control valve controlling circuit card. The circuit card gain was readjusted to the proper value for control valve operation. The operator performed as required. WR 130726

Comment: The improper adjustment of the gain indicates this may have been a maintenance-related failure.

4. **Event:** CVCS volume control tank valve operator failed
Discovery Date: 8/16/87
Cause Cat.: Unknown
Cause Desc.: Burned/Burned Out; Mechanical Damage/Binding

Narrative: The volume control tank no. 1 outlet control valve would not open after closing for safety injection during startup. The motor burned up opening. The valve operator had a broken drive nut apparently broken when pulling the disc off its seat. The operator had put excessive close thrust on the valve. The burned up motor and broken drive nut were replaced. The actuator was reseated to ensure proper torque output. WR 951[illegible]3. WR 94986. WR 131717.

Comment: The problems described in the narrative of the valve failure suggest that the failure may have been maintenance related.

5. **Event:** CVCS cation bed demineralizer supply valve stem broke
Discovery Date: 3/22/88
Cause Cat.: Unknown
Cause Desc.: Normal/Abnormal Wear; Aging/Cyclic Fatigue

Narrative: The cation bed demineralizer 1 in the supply line from the mix bed demineralizer valve was found inoperable by the operator. The unit was at power. The stem broke on the valve and pulled out of the assembly. The valve had worn internals. WR 134361. The bonnet assembly, gaskets, diaphragm, and O-rings were replaced; the valve was torqued and functionally verified as in proper operation.

Comment: This valve failed previously on 11/4/87 when a chain link to the valve operator fell off a sprocket; also the valve was leaking due to normal wear of the internals; two master links in the chain were replaced and a new diaphragm stem and bonnet were installed.

6. **Event:** CVCS valve operator on the charging flow control valve failed
Discovery Date: 7/7/87
Cause Cat.: Unknown
Cause Desc.: Out of Calibration

Narrative: The charging flow control valve was leaking by. It was found by an operator while the unit was being refueled. The valve operator was not closing fully due to a low air supply pressure. The valve was not seating properly. WR 065861. The air supply pressure was adjusted and set the valve travel. Checked for proper operation.

Comment: The improper air supply pressure indicates that this failure may have been maintenance related.

7. **Event:** Reactor Protection and Logic system SG flow transmitter (MCFFT5060) out of calibration
Discovery Date: 3/13/86
Cause Cat.: Unknown
Cause Desc.: Out of Calibration

Narrative: Steam generator 1D feedwater flow transmitter for channel #1 failed low. The plant was normally operating. The transmitter was found out of calibration for an unknown reason. The transmitter was recalibrated. W/R 122361.

Comment: This transmitter had the same problem twice previously on 3/7/86 and 1/21/86. In each of these cases the transmitter was recalibrated and the cause category was unknown.

8. **Event:** Reactor Protection and Logic system main steam flow transmitter (MSMFT5050) out of calibration and water in junction box
Discovery Date: 9/18/87
Cause Cat.: Unknown
Cause Desc.: Foreign/Incorrect Material; Out of Calibration

Narrative: Main steam flow transmitter channel No. 2 from steam generator "C" was found out of calibration during a refueling surveillance test. The flow transmitter had water in the pull junction box below the transmitter. The transmitter was out of tolerance by 6.7% high throughout the range. The flow transmitter pull junction box was drained, all mechanical connectors were tightened, and the transmitter was calibrated for proper operation. WR 065961

Comment: The presence of water in the junction box and the need to tighten all connections indicate that this failure may have been maintenance related.

APPENDIX C

INDICATOR TECHNICAL ISSUES

Appendix C contains details of the algorithm methods being explored to address concerns expressed during the Demonstration Project over how the proposed indicator introduced "ghost" indications and suppressed "shadow" indications.

APPENDIX C

INDICATOR TECHNICAL ISSUES

As initially presented in AEOD/S804B, the maintenance indicator used a simple computational algorithm that compared failure counts over a sliding five-month time interval. Only when a selected threshold value was exceeded did it flag the comparative change as being significant. The indicator was based on selected components in selected systems and it trended the summation of the cumulative indicator flags for each system considered based on all component failure indications within these selected systems. All failures of the equipment as reported to NPRDS were included if they were of an immediate or degraded nature, reported incipient failures were excluded. As a result of this initial construction and bases, several compromises were introduced into the indicator's precision and usefulness to utility staffs. These included being a system-based rather than a component-based indicator, tracking of only some of the systems reportable to NPRDS with exclusion of most safety systems, introduction of "ghost" indications and suppression of "shadow" indications. During the Demonstration Project, several methods and modifications have been explored to address these problems.

Algorithm Refinements

The algorithm used in constructing the indicator was very simple. It processed the selected NPRDS failures by first counting the failures by calendar month using the NPRDS failure discovery date. It then looked for a relative increase in the failure frequency within a moving five-month window, comparing the average number of failures in the last two months to the average number of failures in the first three months. When this difference exceeded a fixed threshold value, a marker was assigned to the latest month of the five-month period. If the failure count for the fourth month is high enough, however, the overall average for the fourth and fifth months can be great enough to produce an indication in the fifth month even when there were zero failures in the fifth month. This "ghost tick" phenomena was identified early in the development of the proposed indicator but the formula was not modified since it was felt that sensitivity to the magnitude of a failure jump increase was desirable and the precise placement of indications was not critical.

Conversely, the original calculation averaging also led to some significant failure increases not generating indications. This "shadowing" of indications occurred when significant increases in failures in a preceding month, when included in the three-month average used in the algorithm, overshadowed the two-month average associated with the later failure increase. This phenomenon was also recognized during the indicator development but this lack of indication was considered to not be a problem given the anticipated way that the indicator was meant to be used.

Two revised calculational methods are being explored to eliminate the "ghost ticks" while capturing "shadow ticks", thereby yielding a more precise set of indications. Both of these exploratory calculational methods still employ the same sliding five-month time window used in the original algorithm. They differ from the original algorithm in the methods used to treat the failure information within the five-month window.

Three-month Averaging: In the three-month averaging method, the algorithm is applied to the failure data, as originally proposed. If the average number of failures for the last two months of the five-

month window exceeds the average number of failures for the first three months of the time window by the threshold limit of 1.01, the algorithm calculation is satisfied such that an indication would be generated for the fifth month. At this point, a check of this indication is made to verify that it is not a ghost tick. This check is performed by averaging the values of the failure counts in the first three months of the time window being considered. If the actual failure count value in the fifth month exceeds the first three-month average for this window, the indication is permitted to remain. If the value of the fifth month does not exceed the average value of the first three months then the indication is eliminated.

If the average of the last two months of the five-month window does not exceed the average of the first three months by the threshold limit, checks are made to determine if an indication should be generated but is being "shadowed" by previous recent failure histories. This check is performed by averaging the values of the failure counts in the first three months of the time window and substituting this average value for the highest value in the three-month period. The algorithm is then completed using the actual failure values for the last two months of the five-month period. If the threshold value of the algorithm is now exceeded, an indication is generated and retained for this fifth month.

Five-month Averaging: The five-month averaging method uses the same algorithm and threshold as used in the original indicator. The difference occurs once a failure indication is generated. In the five-month averaging method, once an indication is generated the data values to be used in subsequent calculations are revised. This is accomplished by substituting the average value of the failures for the actual values of the failures in the five-month time window that resulted in an indication being generated for the fifth month. The time frame is then shifted one month and the original algorithm is applied but now the first four months of the five-month window are average failure values, not actual values. If no failure indication is generated for this new time window, the window is shifted another month with the first three months of the window retaining the old average value and the last two months containing actual monthly failure counts. If no indications are generated, the window is shifted again and the process is repeated. This continues until a new indication is generated. Once a new indication is found, the actual failure values for the five-month window involved in the new indication are retrieved, if necessary, and a new five month average is determined. These average values are then substituted for the actual values and the process outlined above is repeated.

These processes are continued for the entire time period under consideration for both the system-based and the component-based sets of NPRDS equipment failures for each plant. Comparative graphs of the cumulative results of these efforts are plotted. The following examples illustrate how the revised algorithms compare with each other and with the original approach. The examples are based on actual NPRDS failure data for plants which were represented in the Demonstration Project. In these examples, an "F" denotes an indication found by all three methods, a "G" represents ghost indications that are eliminated by the revised calculation method, and an "S" notes a shadow indication which is added by a revised calculation method.

In the first example, a plant experienced 57 failures in systems and components used in constructing the original indicator. Of these, 41 failures were experienced in just two systems. These 41 failures resulted in the generation of a total of eight indications, four in each of the two systems, when the original algorithm was applied. The remaining 16 failures were distributed among six other systems and these failures resulted in no additional indications. The distribution of the 41 failures between the two systems is shown in Figure C.1. Included in this figure are the

comparative indications generated when the original and the two revised algorithms are applied to this data.

MONTH	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J
Failures																												
System A	0	2	0	1	1	0	1	0	0	0	0	0	3	0	2	0	2	0	0	1	0	2	0	5	0	1	1	0
System B	0	1	0	0	2	0	0	2	1	2	0	0	3	1	0	0	0	0	2	1	0	0	0	3	0	0	1	0
ALGORITHM																												
Original																												
System A					-	-	-	-	-	-	-	-	F	G	-	-	-	-	-	-	-	-	-	F	G	-	-	-
System B					-	-	-	-	-	-	-	-	-	F	-	-	-	-	-	F	-	-	-	F	G	-	-	-
3-Month																												
System A					-	-	-	-	-	-	-	-	F	-	-	-	-	-	-	-	-	-	-	F	-	-	-	-
System B					-	-	-	-	-	-	-	-	-	F	-	-	-	-	-	F	-	-	-	F	-	-	-	-
5-Month																												
System A					-	-	-	-	-	-	-	-	F	-	-	-	-	-	-	-	-	-	-	F	-	-	-	-
System B					-	-	-	-	-	-	-	-	-	F	-	-	-	-	-	F	-	-	-	F	-	-	-	-

Figure C.1 Example Application of Various Algorithms

In this example, both of the revised algorithms eliminated three "ghost" indications. The failure distribution was such that neither revised algorithm determined that additional "shadow" indications were present.

In the following example, a different plant experienced 229 failures, with 35 of these failures occurring in one particular system. Applying the original algorithm to these failures resulted in the generation of three indications. In this case, the application of the revised algorithms both eliminated one "ghost" indication but found one "shadow" indication. Figure C.2 illustrates these indications.

MONTH	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J
Failures																												
System C	0	5	1	0	0	1	1	0	0	3	3	0	1	0	1	0	0	0	7	0	1	3	0	2	2	2	1	1
ALGORITHM																												
Original																												
System C					-	-	-	-	-	-	F	-	-	-	-	-	-	-	F	G	-	-	-	-	-	-	-	-
3-Month																												
System C					-	-	-	-	-	-	F	-	-	-	-	-	-	-	F	-	-	S	-	-	-	-	-	-
5-Month																												
System C					-	-	-	-	-	-	F	-	-	-	-	-	-	-	F	-	-	S	-	-	-	-	-	

Figure C.2 Additional Example Application of Various Algorithms

Thus for this example, the total number of indications remains the same. However, the revised algorithms yield a different distribution of the indications over the time period being considered. Comparisons of additional examples reveal that the two revised methods are equally sensitive to capturing "shadow" indications but the five-month averaging method is more sensitive and eliminates additional "ghost" indications.