U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-454, 50-455
License Nos:	NPF-37, NPF-66
Report No:	50-454/97004(DRS); 50-455/97004(DRS)
Licensee:	Commonwealth Edison Company
Facility:	Byron Generating Station, Units 1 & 2
Location:	4450 N. German Church Road Byron, IL 61010
Dates:	April 7 - 15, 1997
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EXECUTIVE SUMMARY

Byron Generating Station, Units 1 & 2
NRC Inspection Report 50-454/97004(DRS), 50-455/97004(DRS)

This inspection included a review of the licensee's implementation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The report covers a seven day on-site inspection by regional and Office of Nuclear Reactor Regulation (NRR) inspectors, and a contractor from Brookhaven National Laboratory.

In general, the program met the requirements of the maintenance rule (MR); however, this was only recently accomplished as a result of changes implemented from the Site Quality Verification (SQV) audit findings.

Operations

- Operators' knowledge was consistent with their responsibility for implementation of the MR. There was no indication that the MR detracted from the operators' ability to safely operate the plant. Using the work window matrix and the weekly on-line risk book helped operators monitor and limit the risk associated with taking equipment out-of-service.

Maintenance

- Structures, systems, and components (SSC) with the exceptions of the SSC functions identified in the SQV audit, were properly scoped into the MR. However, documentation to support scoping decisions was limited.

- The expert panel was composed of well-qualified, experienced personnel. The Byron Individual Plant Examination (IPE) was used in conjunction with the panel's experience base to assess the risk significance of the SSCs. The risk ranking process was generally acceptable, but a continually evolving process. With the possible exception of several ventilation systems, the inspectors did not identify any improperly ranked systems in the licensee's recent risk ranking determination. Weaknesses in the approach included the use of an outdated IPE and inadequate documentation of the expert panel's determinations.

- The procedure for performing periodic assessments met the requirements of the rule and the intent of the Nuclear Management Resource Council (NUMARC) implementing guidance. An assessment, however, had not yet been completed.

- The licensee's proposed method of balancing reliability and unavailability met the intent of the MR. Balancing, however, had not yet been performed.

- The licensee's revised site policy memo provided adequate guidance to address the risk associated with on-line maintenance activities for Modes 1-4. The licensee's shutdown risk management program appeared to effectively address risk associated with a shutdown unit.

- The establishment of performance criteria and goal setting was considered adequate, although in many cases were only recently established or revised. Performance criteria for reliability for safety significant SSCs, however, were deficient in that the functional failure criteria technical bases were not commensurate with the reliability values assumed in the probabilistic risk assessment. As such, the licensee had not demonstrated that the performance or condition of SSCs within the scope of 10 CFR 50.65 were being effectively controlled through the performance of appropriate preventive maintenance. The performance criteria established for fuel handling and emergency lighting systems were not adequate to monitor the effectiveness of maintenance for the SSCs under (a)(2).

- The licensee had adequately scoped tanks, supports, buildings, and enclosures as structures under the MR. The structure monitoring program contained adequate performance criteria and guidance to address structures under the MR.

- The licensee had properly integrated the MR into the existing industry operating experience (IOE) program. Adequate provisions had been made to incorporate information from the IOE program into the goal development and periodic assessment processes.

- The material condition of the plant systems examined was very good. With a few minor exceptions, the systems appeared to be well managed and were free of corrosion, oil, water, steam leaks, and extraneous material.

Quality Assurance

- The licensee's SQV audit was appropriately conducted and identified significant issues. The use of independent personnel and guidance from previously issued NRC MR inspection reports provided significant insight into the MR program. The 1997 audit was considered a program strength. A non-cited violation was based on the results of the audit findings.

Engineering

- System engineers (SEs) were generally experienced and knowledgeable about their systems; however, they exhibited a limited understanding of the MR. Although SEs were not actively involved in MR implementation, the licensee was in the process of increasing the SEs responsibilities with respect to the MR.

Report Details

Summary of Plant Status

Unit 1 and Unit 2 were operating at full power during the inspection.

This inspection included a review of the licensee's implementation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The report covers a 7 day on-site inspection by regional and NRR inspectors, and a Brookhaven National Laboratory consultant.

I. Operations

O4 Operator Knowledge and Performance

O4.1 Operator Knowledge of Maintenance Rule

a. Inspection Scope (62706)

During the inspection of the implementation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," the inspectors interviewed four senior reactor operators to determine if they understood the general requirements of the rule and their particular duties and responsibilities for its implementation.

b. Observations and Findings

The inspectors determined that the operators had a general working knowledge of the MR and their role in its implementation. The Byron on-line maintenance process utilized a cycle schedule containing 12-week rotating quarters, which offered recurring windows to work on major safety-related and safety (risk) significant equipment. The work window was intended to permit the maximum bundling of maintenance tasks to minimize the number of maintenance outages on equipment. Planned and emergent work during Modes 1 through 4, was addressed by Byron Site Policy Memo 600.13, "On-Line Maintenance," Revision 3. The policy provided a methodology and expectation for managing day-to-day maintenance activities. The operators stated that their duties included review of on-line activities and comparison of these activities with the work window matrix and the weekly on-line risk book to minimize risk. The work window matrix was used to identify systems that had been reviewed from the standpoint of minimizing risk. In addition, the operators were tasked with the timely removal and restoration of equipment and providing input into the equipment out-of-service database.

The operators indicated that the MR was integrated with their day-to-day activities, and that the MR did not impose additional administrative burdens that distracted them from their responsibility to safely operate the plant. The operators noted that the MR aided the decision making process as to the combinations of equipment that can be safely taken out-of-service.

c. Conclusions

Operators' knowledge was consistent with their responsibility for implementation of the MR. There was no indication that the MR detracted from the operators' ability to safely operate the plant. Using the work window matrix and the weekly on-line risk book helped operators monitor and limit the risk associated with taking equipment out-of-service.

II. Maintenance

M1 Conduct of Maintenance

The primary focus of the inspection was to verify that the licensee had implemented a maintenance monitoring program which satisfied the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of the Maintenance at Nuclear Power Plants," (the maintenance rule). The inspection was performed by a team of three regional inspectors and a consultant from the Brookhaven National Laboratory. Assistance and support were provided by one member of the Quality Assurance and Maintenance Branch, NRR.

M1.1 SSCs Included Within the Scope of the Rule

a. Inspection Scope (62706)

The licensee's MR was described in procedure BVP-37, "Maintenance Rule Implementation and Compliance Program," Revision 4. The program described the methodology used to select (scope) the structure, system, and component (SSC) functions under the MR. The methodology consisted of the following eight questions:

- Whether the SSC function was safety related?
- Whether the safety-related failure could cause loss of reactor coolant system (RCS) integrity?
- Whether safety-related failure could cause the inability to shutdown the reactor?
- Whether safety-related failure could cause inability to prevent or mitigate accidents or transients?
- Whether the nonsafety-related SSC was used in emergency operating procedures (EOPs)?
- Whether nonsafety-related SSC failure could result in safety-related system failure?
- Whether nonsafety-related SSC failure could cause a safety-related system actuation or plant trip?
- Whether the nonsafety-related SSC failure could cause the inability to mitigate accidents or transients?

The scoping process was exclusionary, rather than the inclusionary process outlined in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." In Byron's exclusionary process, all plant

systems and structures were considered as a possible candidate to be within the scope unless specifically excluded by the expert panel during the scoping process.

From the 112 systems at Byron, the licensee determined which SSC functions were within scope of the MR. Each system performed one or more functions, often with redundant trains of equipment. A comprehensive MR computer database of these functions was developed for evaluation against the scoping criteria. The 112 systems included approximately 400 SSC functions. The expert panel evaluated each SSC function using the criteria mentioned above to determine if the function was within the scope of the MR. Based on results of these evaluations, 76 systems were identified or approximately 296 SSC functions as being in-scope of the MR. While the inspectors did not identify any additional SSCs that needed to be within the scope of the MR, the licensee's recent SQV audit identified six additional SSCs, including the communications and emergency lighting systems, that were not included in the initial scope of the MR program. The SQV audit results were further discussed in Section M7 of this report.

In general, the scoping of SSC functions was good. Documentation available for review consisted of the SSC scoping sheet, "Disposition/Scoping of SSCs Into or From the Maintenance Rule", which included the reason for scoping, and eight questions developed from NUMARC 93-01 guidance. There was little documentation, however, to support the responses to the scoping questions.

c. Conclusions

With the exceptions of the SSCs identified in the SQV audit, the inspectors concluded that Byron SSCs were properly scoped into the MR program. However, documentation supporting the basis for scoping SSC functions was limited.

M1.2 Safety (Risk) Determination, Risk Ranking, and Expert Panel

a. Inspection Scope

Paragraph (a)(1) of the rule requires that goals be commensurate with safety. Additionally, implementation of the rule using the guidance contained in NUMARC 93-01, required that safety be taken into account when setting performance criteria and monitoring under paragraph (a)(2) of the rule. This safety consideration was to be used to determine if the SSC should be monitored at the system, train or plant level. The inspectors reviewed the methods and calculations that the licensee established for making these risk determinations. The inspectors also reviewed the risk determinations that were made for the specific SSCs reviewed during this inspection. NUMARC 93-01 recommended the use of an expert panel to establish safety significance of SSCs by combining Probabilistic Risk Assessments (PRA) insights with operations and maintenance experience, and to compensate for the limitations of PRA modeling and importance measures. The inspectors reviewed the composition of the expert panel and experience and qualifications of its members. The inspectors reviewed the licensee's expert panel process and the information available which documented the decisions made by the expert panel. The inspectors interviewed several members of the expert panel to

determine their knowledge of the MR and to understand the functioning of the panel.

b.1 Observations and Findings on the Expert Panel

The licensee had established an expert panel to perform the initial SSC scoping, identify SSC risk significance, and establish performance criteria for SSC functions. After this work was accomplished, the expert panel was disbanded. The expert panel was reestablished on February 5, 1997, after significant problems with the MR program were identified during an SQV audit.

The licensee had established an expert panel in accordance with the guidance provided in NUMARC 93-01. The expert panel's responsibilities included the final authority for decisions regarding MR scope, to compensate for the limitations of PRA modeling in determining risk significance, and performance criteria selection. In addition, the panel reviewed and approved the dispositions to reclassify SSCs from (a)(2) to (a)(1) and (a)(1) to (a)(2).

The expert panel included plant personnel experienced in engineering, PRA, operations, maintenance, and work scheduling. The expert panel possessed a total of greater than 80 years of nuclear power experience.

The inspectors noted that there was a lack of documentation to support the decisions made during the expert panel meetings. There were no meeting minutes for the initial expert panel meetings and the meeting minutes for recently convened panel lacked the basis for many decisions. In addition, the expert panel members could not recall the details or what information was used during the decision making process.

c.1 Conclusions on Expert Panel

The expert panel composition was considered appropriate; consisting of well-qualified, experienced personnel. PRA insights were combined with operations and maintenance experience to compensate for the limitations of probabilistic risk assessment modeling to assess the risk significance of the SSCs. The lack of documentation for the basis of decisions made by the expert panel was considered a weakness.

b.2 Observations and Findings on Risk Determinations

b.2.1 Analytical Risk Determining Methodology

During the inspection, the inspectors reviewed the Byron Individual Plant Examination (IPE), modified IPE, Individual Plant Examination of External Events (IPEEE), and interviewed the IPE representatives. The licensee's PRA deviated to a degree from the traditional PRA approach in that the systems analysis (Level 1) and containment analysis (Level 2) portions of the PRA were integrated by "plant response trees" (PRTs). The PRTs depicted the combinations of interactions that could impact the plant behavior from the initiating event to an end state characterized by retention of fission products within the containment boundary or

release to the environment. The licensee considered the PRA model to be a large event tree, small support state model. Due to the recent submittals of the IPEEE (December 1996) and the modified IPE (March 27, 1997), the MR program was based on the original IPE submittal of April 1994, which included generic industry data or pre-1993 plant-specific data. The licensee was scheduled to update the PRA/IPE by approximately April 1998. The update would include recent plant-specific data accumulated from implementation of the MR program. The PRA model will also be revised to a linked fault tree model.

The original IPE identified that a procedural enhancement to cross-tie a 4160V engineered safety features (ESF) bus to the other unit for cases with a loss of one bus would significantly reduce the core damage frequency (CDF). The licensee indicated that all equipment, with the exception of alarms for Bus 141, had been included within the scope of the MR as having a significant mitigating function.

The original IPE assumed that steam generator (SG) tube ruptures were not as likely to progress to core melt because a different SG design and rating led to smaller diameter tubes as compared to the licensee's Zion station. That is, a tube rupture was stated to progress more slowly due to a smaller leak rate between the primary and secondary side, so that core damage would be less likely during the first 24 hours following a tube rupture. The CDF due to SG tube ruptures were reported by the licensee to account for less than 0.4 percent of the total CDF. The inspectors noted that the Unit 1 SGs were scheduled for replacement in November 1997 because of a current 15-21% of the tubes having been plugged. As a result of this degradation, the assumptions regarding SG tube ruptures may need to be reverified during the planned updating process for the IPE.

To determine the risk significance of SSCs from the perspective of the Level 1 PRA, the licensee adhered to the guidelines of NUMARC 93-01. The licensee utilized the risk reduction worth (RRW) greater than 1.005, 90 percent of CDF contribution, and risk achievement worth (RAW) greater than 2.000 importance measures for those systems modeled in the PRA model. The results of the risk ranking determination by means of the RRW, 90% of CDF, and RAW were presented to the new expert panel for evaluation.

b.2.2 Adequacy of Expert Panel Evaluations

Of the 76 systems determined to be within the scope of the MR, the expert panel evaluated 38 systems for risk significance using the Delphi process similar to that described in NUMARC 93-02, "A Report on the Verification and Validation of NUMARC 93-01." The following functions were described in the NUMARC document:

Four "Accident Response Functions"

- Required to shutdown the reactor and maintain it in a safe shutdown condition.
- Required to maintain the reactor coolant pressure boundary.
- Required to remove atmospheric heat and radioactivity from containment and maintain containment integrity.

- Required to remove heat from the reactor.

Six "Normal Operations Functions"

- Required to provide primary heat removal.
- Required for power conversion.
- Required to provide primary, secondary, or containment pressure control.
- Required to provide cooling water, component, or room cooling.
- Required to provide electric power (ac, dc power).
- Required to provide other motive or control power (instrument air).

Each of the above functions was assigned a specific numerical weight in accordance with NUMARC 93-02 and BVP 800-37, and used in Table BVP 800-37T2, "Determination of Risk Significance." For each system within the scope of the MR, the licensee's expert panel then assigned a value from 1 to 10 in order of importance of that system to performing the function. The expert panel then determined a weighted value for each of the above functions by multiplying the assigned value times the specific numerical weight for that function. The weighted values for each function were then summed to provide a "Risk Factor" for each system. The expert panel considered systems with a "Risk Factor" equal to or greater than the risk factor for the diesel oil system (185.5) to be risk significant.

Thirty-three (33) of the 38 systems were considered to be risk significant either by the importance measures resulting from the PRA or by the expert panel Delphi process. Approximately 28 systems or subsystems were modeled in the PRA. Overall, the inspectors considered the licensee's risk ranking process to be an evolving process that was being reevaluated as a result of the SQV audit this year. The inspectors did not identify any improperly ranked systems based on the April 4, 1997, Delphi process. The inspectors noted that the importance measures for those systems modeled in the PRA were based on data that was current only up until 1992. A weakness in the licensee's risk significance determinations was the use of an IPE that had not been updated since its original submittal. The licensee indicated the PRA and IPE updating process should address this issue.

The licensee could not provide any documentation concerning the risk significance of the remaining 38 systems that were not formally evaluated by the Delphi process other than to state the expert panel considered those systems to be of low risk significance by consensus. The inspectors identified 4 of the 38 systems not formally evaluated by the Delphi process where the low risk significance ranking may not be appropriate. These were the ventilation systems for the diesel generator (DG), battery rooms, miscellaneous electrical equipment room (MEER), and control room. The equipment that the ventilation functions support were considered high risk significant. The loss of the ventilation systems would result in the loss of equipment in these areas.

During the inspection, the licensee's staff stated the SSCs were low risk significant because compensatory measures could be put in place. For example, if the DG room ventilation system was inoperable, the licensee would use portable fans in doorways to provide ventilation. However, the licensee had not considered how the portable fans would be powered if the DG was the only electrical power supply.

The licensee did not justify having a support system less safety significant than the equipment that requires this support system to operate. The license did not demonstrate that procedures were available and that actions for compensatory measures could be taken during an actual event before the room temperature affected the high safety significant equipment. This issue is considered an Inspection Follow-up Item (IFI) (50-454/455/97004-01(DRS)) pending the licensee providing additional information to show that the four ventilation systems did not have to be classified as safety significant because other compensatory measures could be taken to prevent room temperatures from affecting the equipment in the rooms.

For the Level 2 PRA aspects, namely the prevention of radioactive releases, the expert panel considered all of the containment functions. For the containment building itself (designator BM), the panel determined it to be risk significant by both the PRA and the Delphi process. The containment spray system was considered to be risk significant based on its contribution to reducing large early releases. For the MR, all penetrations were grouped into a "super-system," primary containment, which was classified as risk significant. The containment heating, ventilation, and cooling system was considered to be risk significant both on the basis of the PRA and by the Delphi process.

Other structures were considered to be risk significant by applying the statement: "If the structure supports, houses, or protects any risk significant SSCs, then conservatively, the structure should be considered risk significant unless otherwise documented by the Expert Panel." The inspectors reviewed the licensee's risk determinations for structures and considered them acceptable.

It appeared that the original expert panel had improperly ranked several systems as being low risk significant. Systems that were recently ranked as risk significant included containment spray, instrument air, circulating water, and diesel fuel oil. The original panel also was not presented with the results of the PRA importance measure calculations upon which to make decisions concerning ranking. The meeting minutes of the new expert panel did not always provide the basis for decisions.

c.2 Conclusions on Risk Determinations

The risk ranking process was generally acceptable but a continually evolving process with the latest risk ranking determination issued on April 4, 1997, just prior to the inspection. With the possible exception of four ventilation systems, the inspectors did not identify any improperly ranked systems in the licensee's most recent risk ranking determination. However, weaknesses in the approach included the use of an outdated IPE and the limited documentation of expert panel's determinations.

M1.3 (a)(3) Periodic Evaluations

a. Inspection Scope

Paragraph (a)(3) of the MR requires that performance and condition monitoring activities and associated goals and preventive maintenance activities be evaluated, taking into account where practical, industry wide operating experience. This evaluation was required to be performed at least one time during each refueling cycle, not to exceed 24 months between evaluations. The inspectors reviewed the procedural guidelines for these evaluations.

b. Observations and Findings

The licensee's instructions for conducting periodic evaluations were contained in procedure BVP 800-37, Attachment F. The procedure provided adequate guidance for preparing periodic assessments, which would meet the requirements of 10 CFR 50.65(a)(3) and the intent of NUMARC 93-01, Sections 12 and 13.5. The licensee, however, had not yet performed a periodic assessment since the MR went into effect. The licensee intended to perform the assessment for both units coincident with the Unit 1 refueling outages. The next Unit 1 refueling outage was scheduled during the Fall of 1997. Since a periodic assessment has not been completed, this will be considered an IFI (50-454/455/97004-02(DRS)) pending the licensee completion of an assessment and subsequent review by the NRC.

c. Conclusions

The procedure for performing periodic assessments met the requirements of the rule and the intent of the NUMARC implementing guidance. An assessment, however, had not yet been completed and will remain an open issue for future followup.

M1.4 (a)(3) Balancing Reliability and Unavailability

a. Inspection Scope

Paragraph (a)(3) of the MR requires that adjustments be made where necessary to assure that the objective of preventing failures through the performance of preventive maintenance was appropriately balanced against the objective of minimizing unavailability due to monitoring or preventive maintenance. The inspectors reviewed the licensee's plans to ensure this evaluation was performed as required by the rule.

b. Observations and Findings

The licensee's basis for balancing reliability and availability was contained in BVP 800-37. The licensee's approach consisted of monitoring SSC function performance against the established performance criteria. The licensee had not balanced reliability and unavailability prior to the inspection. This task was to be performed during the periodic assessment. The licensee was, however, reviewing and evaluating the effectiveness of the preventive maintenance (PM) program. The system engineers were reviewing planned PM tasks to eliminate ineffective tasks

and redirect efforts toward a condition based maintenance strategy. In addition, scheduling was coordinated so that the frequency of system maintenance outages were minimized.

c. Conclusions

The inspectors concluded that the licensee's proposed method of balancing reliability and unavailability would meet the intent of the MR. The licensee had not balanced reliability and unavailability as it will be performed as part of the periodic assessment and will be reviewed by the NRC as part of the IFI on periodic assessments.

M1.5 (a)(3) On-line Maintenance Risk Assessments

a. Inspection Scope

Paragraph (a)(3) of the MR requires that when removing plant equipment from service the overall effect on performance of safety functions be taken into account. The guidance contained in NUMARC 93-01 required that an assessment method be developed to ensure that overall plant safety function capabilities were maintained when removing SSCs from service for preventive maintenance or monitoring. The inspectors reviewed the licensee's procedures and discussed the process with the site maintenance rule owner (SMRO), the PRA engineer performing on-line risk assessments, plant operators, and planning and scheduling personnel.

b. Observations and Findings

The licensee's on-line maintenance program was controlled under Site Policy Memo No. 600.13, with responsibility being assigned to the cycle manager. In general, the policy provided adequate guidance to address the risk associated with on-line maintenance activities. The site policy included guidance for Modes 1-4. The policy had been recently revised to address SQV concerns for on-line maintenance activities during Modes 2-4, which were not included in Revision 2 to the policy. The policy revisions included additional guidance for Mode 4 with respect to the risk significance of the auxiliary feedwater (AFW) and safety injection (SI) systems, the steam generators, the steam dumps and main steam power-operated relief valves (PORVs), and the pressurizer PORVs. For Mode 3, the guidance indicated that for reactor coolant system (RCS) pressure below 800 psig, the SI accumulators need not be considered for risk evaluation since they were isolated. For Mode 2, no changes were required.

The site policy memo consisted of three tables and attachments A through F. Table 1, entitled "Byron Cumulative CDF Change Criteria," indicated that changes in cumulative CDF up to 30% (a factor of 1.3 times the baseline CDF) were considered non-risk significant. Larger cumulative CDF changes required either further evaluation or be considered unacceptable (factors up to 8.7 or above 8.7, respectively). Table 2, "Instantaneous CDF Change Criteria," defined CDF change threshold range factors and divided them into four classifications based on rising factors. GREEN was non-risk significant (1 to 3), YELLOW was non-risk significant only if non-quantitative factors apply (greater than 3 to 20), ORANGE was

potentially risk significant (greater than 20 to 35), and RED as risk significant (greater than 35). For single component unavailabilities, the memo indicated that the CDF change threshold factors will be equal to the RAW importance values. For multiple component unavailability cases, the CDF change would have to be determined using the PRA model.

The screening criteria were of fundamental importance to the licensee's on-line maintenance program, which were defined in Table 3, "Byron Station 12 Week Cycle Schedule System Matrix." For each week a large number of individual systems or system combinations were identified and their corresponding RAW values presented in terms of whether the combinations were considered GREEN, YELLOW, or ORANGE. No RED combinations were allowed for prior planned work. Most combinations were GREEN or YELLOW, with only a few combinations were ORANGE.

The site policy memo provided guidance when emergent work was identified. Attachments A and B were to be used as guidance by the operating shift to take prompt steps to keep the unavailability of equipment important to safety as short as possible. For an unplanned unavailability of equipment from Attachment A, the cycle manager would be responsible for determining the risk impact. Pending activities on systems in Attachment A that would affect risk were to be postponed until the risk had been determined. Emergent work was considered by the licensee to occur very infrequently. The operating staff generally would call one of the cycle managers to receive verbal instructions or approval whenever emergent work occurred. The licensee staff did not typically document the on-line risk process for approving emergent work.

The inspectors reviewed examples of completed Attachment C's, "On-Line Maintenance Weekly Schedule Review," and also risk evaluations of planned maintenance activities not falling within the bounds of Table 3. No problems were identified. These were typically performed by the site PRA Group and directed to the cycle managers. The PRA Group was not heavily involved in the scheduling process because of the extensive amount of pre-analyzed equipment combinations identified on Table 3 of the site policy memo.

The inspectors noted that the licensee's Electronic Work Control System (EWCS) provided the operators the status of all equipment out-of-service in the plant. The inspectors considered EWCS as an aid in reducing the possibility of unanalyzed emergent work situations. However, equipment within the scope of the MR were not specifically identified within EWCS.

Shutdown safety was governed under Site Policy Memo No. 600.12, "Shutdown Risk Management," Revision 6. This policy memo was essentially an outline of safety concerns. Detailed information was provided in the outage guidelines, which the licensee issued for each outage, whether a scheduled refueling outage or a forced outage. These guidelines provided detailed instructions for addressing issues such as: loss of decay heat removal, loss of fuel pool cooling, loss of RCS inventory, loss of fuel pool/reactor cavity inventory, loss of off-site power, reactivity control/shutdown margin, and containment closure. The outage guidelines were supplemented with specialized tables issued for major activities

with involved risk. Specifically the licensee provided examples of measures to reduce involved risk for reactor vessel head removal, service water valve installation and repairs, ESF Bus 141 outage with DC 111 cross-tie, and switchyard breaker work. The licensee's program for shutdown risk management at the time of the inspection was a qualitative program. The licensee was planning to introduce an industry standard computerized risk monitoring program for the next outage scheduled for November 1997.

c. Conclusions

The inspectors concluded the licensee's revised site policy provided adequate guidance to address the risk associated with on-line maintenance activities for Modes 1-4. The licensee's shutdown risk management program appeared to effectively address risk associated with a shutdown unit.

M1.6 (a)(1) Goal Setting and Monitoring and (a)(2) Preventive Maintenance

a. Inspection Scope

The inspectors reviewed program documents in order to evaluate the process established to set goals and monitor under (a)(1) and to verify that PM was effective under (a)(2) of the rule. The inspectors also discussed the program with appropriate plant personnel. The inspectors reviewed the following systems:

(a)(1) systems

Essential Service Water
Fire Protection
Instrument Air

(a)(2) systems

Auxiliary Feedwater
Primary Containment
Neutron Monitoring
Containment Spray
Turbine Electro-Hydraulic Controls

The inspectors reviewed each of these systems to verify that goals or performance criteria were established in accordance with safety, that industry wide operating experience was taken into consideration where practical, that appropriate monitoring and trending were being performed, and that corrective actions were taken when an SSC failed to meet its goal or performance criteria or experienced a maintenance preventible functional failure (MPFF). The inspectors also reviewed performance criteria for SSCs not listed above.

The inspectors reviewed the licensee's process to evaluate onsite passive structures for inclusion under the MR. Structures evaluated by the inspectors included buildings, enclosures, storage tanks, earthen structures, and passive components and materials housed in the aforementioned. In addition, the

5.7E-05, which was an increase of approximately 500% compared to the baseline CDF of 1.15E-05.

The calculation also attempted to validate unavailability data. This was accomplished by dividing the number of days or hours a system was unavailable by the number of days or hours equivalent to 2 years. If there was no basic event for maintenance unavailability for a component, the calculated unavailability was added to the existing random failure rate already incorporated into the PRA model. Based on these assumptions, the calculation results indicated that considering the availability criteria alone, the CDF increased from the baseline IPE value of 1.15E-05 to 2.1E-05 or by 80 percent.

The BVP 800-37 stated that the calculation results should also be considered if more than one FF per train (or a higher performance criterion, where one has been justified) was experienced, such that the PRA reliability assumption would appear to have been challenged, and the SSC should be considered for dispositioning to (a)(1). The inspectors stated that the licensee's performance criteria calculation was inadequate because it under represented the CDF that would result if even one of the risk significant systems reached its established performance criterion of one FF in 2 years. For example, the reliability values associated with the auxiliary feedwater function (AF1), and the essential safety features and reactor protection actuation function (EF1) based on the performance criteria would be greater than the reliability values included in the sensitivity calculation. The technical basis to couple the number of FFs to the failure probability assumptions in the PRA was inadequate. As such, the licensee had not demonstrated that the performance or condition of SSCs within the scope of 10 CFR 50.65 were being effectively controlled through the performance of appropriate PM and is considered to be a violation of 10 CFR 50.65(a)(1) (50-454/455/97004-03a(DRS)).

The inspectors also identified concerns with the performance criteria established for the emergency lighting and fuel handling SSCs.

- <u>Emergency Lighting</u>

  The inspectors noted several problems with the emergency lighting function (LL1). The performance criteria basis for LL1 stated that Appendix R emergency lighting was not included in scope, while the scoping document stated that it was in scope. The licensee stated this was an error in documentation for this function as Appendix R emergency lighting was considered in scope of the MR. In addition, the emergency lighting surveillance results had not been reviewed to identify and evaluate past FFs for emergency lighting units (ELUs). Although the ELUs had only recently been scoped in the MR, a review of past surveillance results would be necessary to establish adequate performance criteria.

  Most ELU components, such as batteries, chargers, and lamps, were considered by the inspectors to be operated until failure since there was not a preventive maintenance program to replace these components prior to their end of life. The majority of battery failures occurred during the scheduled 18-month 8-hour discharge surveillance test. The normal failure rate for

batteries was 10 to 15 percent during this surveillance. ELU quarterly surveillances were somewhat predictive of battery and charger condition because of evaluations performed for water loss and voltage readings, but only represented a minor part of component replacements.

The inspectors identified that the reliability performance criterion of less than or equal to two FFs per ELU per 2 years was not commensurate with safety. The performance criteria would allow an excessive failure rate for each ELU. This could result in the ELUs having a significant failure rate without being evaluated for (a)(1). The number of demands for this standby system were assumed to be eight demands during a 2 year period, which would allow a 37% failure rate for each ELU. The inspectors did not consider this performance monitoring criteria to be predictive because it would not detect degradation before failures occurred and would not help to identify ELU maintenance problems.

The licensee had not established performance monitoring criteria for LL1, which would demonstrate acceptable performance. The licensee's basis for placing the LL1 under the requirements of Section (a)(2) was inadequate. LL1 should have been monitored in accordance with Section (a)(1) and was considered to be another example of a violation of 10 CFR 50.65(a)(1) (50-454/455/97004-03b(DRS)).

- Fuel Handling Equipment

The inspectors identified that the fuel handling equipment function (FH1) to handle and transport fuel and related components reliability performance criteria, established at less than or equal to three FFs in 2 years, was not commensurate with safety. A FF was defined as an event that could potentially damage fuel assemblies during handling or conditions that could impair fuel movement safely. A FF was also defined as the inability of the reactivity control aspects of the spent fuel pool (SFP) racks to maintain Keff less than 0.95 in the SFP without compensatory actions. The inspectors determined that it was an unacceptable risk to require four FFs on the refueling bridge that resulted in the potential for fuel damage prior to evaluating this equipment for (a)(1). The fuel handling system consisted of numerous components where FFs of some equipment may not have a potential for fuel damage. As such, the performance criteria may be acceptable for certain refueling equipment, but it was unacceptable for the above example and for reactivity control problems.

The licensee had not established performance monitoring criteria for FH1, which would demonstrate acceptable performance. The licensee's basis for placing the FH1 under the requirements of Section (a)(2) was inadequate. FH1 should have been monitored in accordance with Section (a)(1) and was considered to be another example of a violation of 10 CFR 50.65(a)(1) (50-454/455/97004-03c(DRS)).

b.2 Performance Criteria for Unavailability

The inspectors reviewed the 33 licensee-specified risk significant SSCs, and identified that unavailability performance criteria had been set for the majority of SSCs. However, the licensee had not set unavailability criteria for several risk significant SSC functions, where any unavailability would have caused a plant trip or required a plant shutdown (e.g., ATWS, instrument power, reactor coolant inventory, fission product barrier, remove heat from reactor to steam generators) and, as such, was monitored by plant-level performance criteria. This was considered reasonable and acceptable.

The licensee staff indicated that the unavailability criteria were developed by:

- identifying the PRA modeled unavailabilities and their origin, i.e., whether they were based on plant-specific or generic data,
- using technical specification limiting condition for operation (LCO) times,
- evaluating the most recent operating history, and
- discussing the information with the expert panel.

The expert panel then determined the individual unavailability criteria for each function.

As previously stated, the unavailability criteria for high safety significant SSCs were different than those assumed in the PRA; however, the sensitivity study indicated only an 80% increase in CDF based on the unavailability performance criteria numbers. Based on this increase in the CDF, the inspectors determined that the unavailability performance criteria established for high safety significant SSCs were acceptable. Although unavailability criteria did not significantly affect CDF, the licensee should ensure during balancing that the performance criteria established remains reasonable based on plant specific unavailability data to ensure PM remains effective.

b.3 Performance Criteria for Non-risk Significant Normally Operating SSCs

The licensee established six plant-level performance criteria that included the following:

- less than or equal to two unplanned manual or automatic reactor trips while critical per unit per 2 years
- less than or equal to two ESF actuations per unit per 2 years
- less than or equal to four percent unplanned capability loss factor per unit per month
- less than or equal to two unplanned entries into a higher level of risk monitoring per outage period per unit per 2 years
- entry into an Unusual Event, Alert, Site Emergency, or General Emergency per the Generating Station Emergency Plan (GSEP)

When a plant level event occurs, the SMRO would assess it against the plant level performance criteria. If a plant level performance criterion was exceeded, the

SMRO would bring the assessment and recommendation to the expert panel to determine if a specific SSC would be considered for transfer to category (a)(1).

b.4 Goals Established for (a)(1) SSCs

The SQV audit had identified that the licensee was not establishing measurable goals when an SSC went into (a)(1). The licensee had considered completion of corrective actions as the goal. Based on this finding, the licensee revised the goal setting policy to establish measurable goals for SSCs in (a)(1).

The inspectors noted that the licensee's revised program had considered safety in establishment of goals. The licensee reviewed Byron, ComEd, and Industry Operating Experience and identified relevant information for all MR functions assigned to (a)(1). The licensee actions plans were appropriate for functions in (a)(1). Goals had been established for the performance required to return the function to (a)(2). The goals were indicative of availability, reliability, or condition of the SSCs. The licensee was performing an update of the monitoring results in terms of the goals established. Goals were being set for the nine functions recently added to (a)(1). Corrective actions appeared to be appropriate for those functions in (a)(1).

b.5 Structures and Structure Monitoring

The inspectors reviewed ComEd corporate procedure NEP-17-03, Revision 0, "Structures Monitoring," and other associated licensee programmatic controls to determine which onsite structures were evaluated for inclusion under the MR. Additionally, a review of the performance criteria and monitoring established for structures within scope was performed.

The inspectors determined the scope of the structure monitoring program included the structures required to be monitored by the MR. The monitoring procedure contained guidance for evaluating structural elements, such as: concrete, structural steel, vertical tanks, masonry, equipment foundations, component supports, buried piping, structural isolation gaps, watertight doors, building siding, and roofing. The structures included within the scope of the rule were divided into zones to ensure all areas would be inspected. Performance criteria were established for safety (risk) significant and low safety significant structures as greater than one or two functional failures per 2 years, respectively. The licensee's evaluation process included three classifications of results: 1) acceptable, 2) acceptable with deficiencies (this classification was further divided into whether repair activities were required or not required to prevent further degradation or to restore design margin, and 3) unacceptable. For each of the structural elements, the structural monitoring procedure identified items that would be considered a functional failure of the element.

The licensee's initial structural walkdown frequencies were based a number of issues, including type of element being inspected and the environment where the element was located. These frequencies may be revised based on the results of the baseline walkdowns or other observed degradation. Although the baseline structural walkdowns have not been completed, the licensee did have a schedule to

complete the remaining walkdowns. The inspectors reviewed the walkdown results for several zones in the auxiliary building and noted that minor deficiencies not affecting the structure's function were being documented, and resolved if required. No major concerns were identified by the licensee on the auxiliary building structures where walkdowns have been completed.

c. Conclusions

The establishment of performance criteria and goal setting was considered adequate, although in many cases were only recently established or revised. Performance criteria for reliability for safety significant SSCs, however, were deficient in that the functional failure criteria technical basis were not commensurate with the reliability values assumed in the probabilistic risk assessment. The licensee had not demonstrated that the performance or condition of SSCs within the scope of 10 CFR 50.65 were being effectively controlled through the performance of appropriate preventive maintenance. The performance criteria established for FH1 and LL1 were not adequate tc monitor the effectiveness of maintenance for the SSCs under (a)(2).

The licensee had adequately scoped tanks, supports, buildings, and enclosures as structures under the MR. The structure monitoring program contained adequate performance criteria and guidance to address structures under the MR.

M1.7 Use of Industry-wide Operating Experience

a. Inspection Scope

Paragraph (a)(1) of the rule states that goals shall be established commensurate with safety and, where practical, taking into account industry-wide operating experience. Paragraph (a)(3) of the rule states that performance and condition monitoring activities and associated goals and PM activities shall be evaluated at least every refueling cycle. The evaluation shall be conducted taking into account industry-wide operating experience. The inspectors reviewed the licensee's program to integrate industry operating experience (IOE) into their monitoring program for maintenance.

b. Observations and Findings on Use of Industry-wide Operating Experience

ComEd corporate procedure NSWP-A-06, Revision 0, "Operating Experience (OPEX)," provided the methodology for evaluating and initiating action for operating experience information at all of the licensee's nuclear stations. The objective of the evaluation was to ensure that lessons learned from operating experiences were used to prevent occurrences of such events and to improve plant safety and reliability.

Interviews and the review indicated that NSWP-A-06 was a structured process for evaluating and processing IOE. The OPEX coordinator was the central input for all operating experience and vendor technical information at Byron. In addition, the OPEX coordinator performed the initial screening of documents for site applicability. Included in the screening review was the completion of the OPEX Reviewers

Guidelines by the OPEX coordinator and a subject matter expert. Step 12 of the guidelines reviewed OPEX evaluation documents for impact on the MR, which included the following two questions: 1) "Will the event/issue described have any impact on reliability or availability performance criteria/goals for any systems?" and 2) "Did the event/issue described result in nonsafety/BOP equipment causing a significant plant transient or prevent a safety-related function from occurring?" The SMRO was notified if either of the above questions was answered "yes". The MR procedure required reviewing IOE when developing goals and as part of the periodic assessment.

c. Conclusions for Use of Industry wide Operating Experience

The inspectors concluded that the licensee had properly integrated the MR into the existing IOE program. Adequate provisions had been made to incorporate information from the IOE program into the goal development and periodic assessment processes.

M2 Maintenance and Material Condition of Facilities and Equipment (61706, 71707)

M2.1 General System Review

a. Inspection Scope

The inspectors conducted a detailed examination of several systems from a MR perspective to assess the effectiveness of the licensee's program when it was applied to individual systems.

b.1 Observations and Findings for Essential Service Water (SX)

The SX system was considered risk significant and had been divided into four SSC functions. The inspectors reviewed the established performance criteria for each of the following functions:

- SX1 - Cooling for essential equipment reliability criterion was established at less than or equal to one FF per train per 2 years. The unavailability criterion was established at less than or equal to 5.4 days per 2 years for the B train and at less than or equal to 14 days per 2 years for the A train.

- SX2 - Ultimate heat sink temperature control reliability criterion was established at less than or equal to one FF per cell per 2 years. The unavailability criterion was established at less than or equal to 54 days per cell per 2 years, with six fans always operable.

- SX3 - Ultimate heat sink level control reliability criterion was established at less than or equal to one FF per train per 2 years. The unavailability criterion was established at less than or equal to 40 days per SX makeup train per 2 years.

- SX4 - Cooling for ESF equipment cubicles reliability criterion was established at less than or equal to one FF per train per 2 years. The

unavailability criterion was established at less than or equal to 28 days per train per 2 years.

The inspectors found that the licensee did not establish FFs per number of demands or per run time as the reliability performance criteria for this high safety (risk) significant system. The licensee had placed the essential service water functions SX1, SX2, and SX3 in a(1) as a result not meeting reliability and unavailability performance criteria because of numerous problems. Goals were established within the licensee's corrective action program to continue monitoring against the performance criteria set for these functions. The licensee had closely monitored the rate of silt buildup in the ultimate heat sink as a result of goals set in (a)(1). The licensee had recently identified additional functional failures for the SX functions during a reevaluation of problem identification forms (PIFs). Root cause evaluation and goal setting were still in progress for these issues.

b.2 Observation and Findings for Fire Protection (FP)

The inspectors reviewed the established performance criteria for the FP emergency alternate limited SX supply and station air compressor (SAC) cooling function (FP1) to provide water to the steam generators and noted that the licensee established a reliability performance criterion of less than or equal to two FFs per train per 2 years and an unavailability performance criterion of less than or equal to 40 days per train per 2 years. The emergency alternate limited SX supply and SAC cooling included the two fire protection pumps and associated valves and piping to SX and SACs. The licensee determined that FP1 was a standby and low risk significant function.

The "OB" FP train had been moved to (a)(1) due to excessive unavailability of the diesel fire pump. Goals had been established to optimize PM and monitor work control effectiveness. The "OA" FP train had been added to (a)(1) due to repeat FF and excessive unavailability. Root cause and goal setting was in progress for the "OA" train. The inspectors reviewed the corrective action for these failures and concluded that the corrective action was adequate.

b.3 Observations and Findings for Instrument Air (IA)

The inspectors reviewed the performance criteria for the IA function to provide station dry filtered instrument air for equipment and instruments (IA1) and noted that the licensee established a reliability performance criterion of less than or equal to one FF per train per 2 years, and an unavailability performance criterion of less than or equal to 60 days per train per 2 years. The inspectors found that the licensee did not establish FFs per number of demands or per run time as the reliability performance criteria for this high safety (risk) significant system. In addition, the licensee established a reliability performance criterion to provide the river screen house with dry filtered instrument air for equipment and instruments function (IA2) of less than or equal to two FFs per train per 2 years, and an availability performance criterion of less than or equal to 60 days unavailability per train per 2 years.

Function IA1 was classified in (a)(1) status during the third quarter of 1996 due to exceeding unavailability criterion of 60 days per year. The instrument air dryer purge exhaust valve experienced repeated failures during post maintenance verification testing. The criteria was exceeded primarily due to improper re-assembly of the instrument air dryer purge valve actuators during PM activities. The root cause investigation determined that the event was as a result of an inadequate repair procedure and inadequate post maintenance verification. The corrective actions to revise the procedure to add assembly and test instructions were completed and the system was in the monitoring phase to return to (a)(2). The inspectors reviewed the monitoring goals and found them to be appropriate.

b.4 Observations and Findings for Auxiliary Feedwater (AFW)

The inspectors reviewed the established performance criteria for the AFW function to provide water to the steam generators (AF1) and noted that the licensee established a reliability performance criterion of less than or equal to one FF per train per 2 years and an unavailability performance criterion of 12 days per 2 years for each of the four trains of AFW (two per unit). The inspectors found that the licensee did not establish FFs per number of demands or per run time as the reliability performance criteria for this high safety (risk) significant system. The availability criterion was based on IPE values and not actual system history such that the criterion may require further evaluation as part of balancing reliability and availability during the periodic assessment. In addition, the licensee established a reliability performance criterion for the anticipated transient without scram (ATWS) function (AF2) of less than or equal to one FF per train per 2 years for each of the six logic circuits (three per unit), which was considered a separate function scoped into the MR program. This criterion, however, was not developed until identified during the SQV audit. No availability criteria was established for ATWS as the system was always considered available.

All trains of the two AFW SSC functions were being monitored under (a)(2) of the MR. This was based on good system availability and only one FF. The FF concerned the 1B AFW pump failure to start during a surveillance test. Two design issues were under evaluation that involved suction transients and oscillations of the AFW control valves. Interim measures were in-place to address each issue prior to final resolution.

b.5 Observations and Findings for Primary Containment (PC)

The inspectors reviewed the established performance criteria for the PC function on containment isolation valves, devices and integrity (PC4) and noted that the licensee established a reliability performance criterion of no repetitive Appendix J or inservice test failures within 2 years and an unavailability performance criterion of less than or equal to one loss of containment isolation function (both devices incapable of providing isolation). In addition, the licensee established a reliability performance criterion for the containment personnel airlocks function (PC3) of less than or equal to one FF per airlock per 2 years for each of (two per unit) and an unavailability performance criterion of less than or equal to 4 days per airlock per 2 years, one airlock always available, and no loss of integrity events. This system

was considered safety (risk) significant and the inspectors considered the performance criteria established to be acceptable.

The PC functions were being monitored under (a)(2) of the MR as no significant issues have been identified. There have been a number of FFs (nine) concerning mostly local leak rate test failures; however, the redundant containment penetration device would maintain the SSC function.

b.6 Observations and Findings for Neutron Monitoring (NR)

The inspectors reviewed the established performance criteria for the NR system to provide indication, alarms and interlocks and trips for neutron flux levels (NR1) and noted that the licensee established a reliability performance criterion of less than or equal to three FFs (all channels combined) per unit within 2 years, and an availability performance criterion of less than or equal to 4 days unavailability per channel per 2 years. In addition, the licensee established a reliability performance criterion for the post accident neutron monitoring function, of less than or equal to one FF per channel per 2 years, and an availability performance criterion of less than or equal to 14 days unavailability per channel per 2 years. The system was classified as non-risk significant.

Although the NR1 was currently in (a)(2), it exited (a)(1) in October 1996. It was placed in (a)(1) on September 15, 1995 as a result of the Unit 1 source range channel N-32 experiencing FFs (noise spiking) and failures of the source range detector assemblies during outages. Detector and cable replacements eliminated the source range spiking problem. Currently, the Unit 2 source range channel N32 experienced steady-state noise when the reactor trip breakers were closed for Byron refueling outage 6. However, it was determined by the licensee that this was not a random spiking problem, as before, but an upward bias of the source range channel and did not affect the operability of the channel.

b.7 Observations and Findings for Containment Spray (CS)

The inspectors reviewed the established performance criteria for the CS function to pump water from refueling water storage tank (RWST) or sump to spray nozzles (CS1) and noted that the licensee established a reliability performance criterion of less than or equal to one FF per train per 2 years, and an availability performance criterion of less than/or equal to 26 days unavailability per train per 2 years. The inspectors found that the licensee did not establish FFs per number of demands or per run time as the reliability performance criteria for this high safety (risk) significant system. in addition, the licensee established a reliability performance criterion to store and provide NaOH to containment spray (CS2) of less than or equal to one FF per train per 2 years, and an availability performance criterion of less than or equal to 26 days of unavailability per NaOH flowpath per 2 years.

In the past 2 years, one FF was attributed to the CS1 function when it was found that the 1B CS pump bearings had been installed incorrectly. There have been no FFs attributed to the CS2 function. The inspectors noted that the material condition of this SSC was good and that it was functioning as designed.

b.8 Observations and Findings for Turbine Electro-Hydraulic (EH)

The inspectors reviewed the established performance criteria for the turbine overspeed protection function (EH2) and noted that the licensee established a reliability performance criterion of less than or equal to one FF per train per 2 years. EH2 was a standby and low safety significant function.

The turbine overspeed protection function included two trains of trip networks per unit, with associated throttle valves (TV), governor valves (GV), reheat stop valves (RSV) and intercept valves (IV). A functional failure was defined as a test result indicating turbines have lost one or more overspeed trip network functions. TVs, GVs, RSVs, and IVs were monitored by their effect on plant level criteria to determine FFs. This function had experienced no FFs or unavailability during the last 2 years.

c. Conclusions for General System Review

The inspectors concluded that the licensee had properly classified each SSC as category (a)(1) or (a)(2). In most cases the performance criteria or goals established appeared appropriate. However, the licensee did not establish FFs per number of demands or per run time as the reliability performance criteria for the high safety (risk) significant systems as noted in the violation. The corrective actions, both in progress and planned, for SSCs appeared adequate. Although the inspectors did not identify in the SSCs reviewed any FFs not previously identified, the licensee had recently identified a number of FFs with the SX system during a reevaluation of PIFs.

M2.2 Material Condition

a. Inspection Scope

In the course of verifying the implementation of the MR using Inspection Procedure 62706, the inspectors performed walkdowns using Inspection Procedure 71707, "Plant Operations," to examine the material condition of the systems listed in Section M1.6.

b. Observations and Findings

With minor exceptions, the systems were free of corrosion, oil leaks, water leaks, trash, and based upon external condition, appeared to be well maintained.

c. Conclusions

In general, the material condition of the systems examined was very good.

M7 Quality Assurance in Maintenance Activities

M7.1 Licensee Self-Assessments of the Maintenance Rule Program

a. Inspection Scope (40500)

The inspectors reviewed a self-assessment conducted by the engineering organization in 1996 and a SQV audit conducted in January 1997, both of which pertained to implementation of the MR.

b. Observations and Findings

The August 1996 self-assessment was conducted by the Performance Monitoring group, which has responsibility for implementation of the MR. The assessment identified a number of issues and recommendations. One of the overall conclusions of the assessment was that the MR program was being effectively implemented. The January 1997 SQV audit, however, identified several significant concerns with the MR program in effect during that time period.

The SQV audit (QAA 06-97-01) was comprised of a multi-disciplined team, which included members from other ComEd facilities and technical consultants. This approach provided an independent viewpoint, which added to the overall quality of the audit. The auditor's use of previously issued NRC inspection reports and guidance to identify areas of concern was considered a strength. As previously stated in the report, the SQV audit identified a number of significant concerns, which included 9 Corrective Action Reports (CARs) and 29 recommendations. Several issues identified were significant enough that almost the entire program has undergone a reevaluation. Some of the more significant findings included the following: SSCs were placed in (a)(1) without establishing measurable goals; six SSCs not included within the scope of the rule; lack of or inadequate performance criteria; performance criteria being exceeded, but the SSC was not placed in (a)(1); and repetitive failures not being identified. Corrective actions have been put in place or planned for these and the other CARs. A nuclear tracking system item was addressing the followup of the 29 recommendations. The majority of the recommendations have already been implemented.

The examples identified above were considered a failure to properly implement the requirements of MR by the July 10, 1996, implementation date. This licensee-identified and corrected violation is being treated as a Non-Cited Violation of 10 CFR 50.65, consistent with Section IV of the NRC Enforcement Policy (50-454/455/97004-04(DRS)).

c. Conclusions

Although the self-assessment identified a number of issues, it did not identify the significant concerns identified by the SQV audit. The inspectors concluded that the licensee's SQV audit was appropriately conducted and identified significant issues. The use of independent personnel and guidance attained from previously issued NRC MR inspection reports provided significant insights into the MR program. The

1997 audit was considered a program strength. The non-cited violation was a direct result of the audit findings.

III. Engineering

E4 Engineering Staff Knowledge and Performance

E4.1 Engineer's Knowledge of the Maintenance Rule

a. Inspection Scope (62706)

The inspectors interviewed system engineers (SEs) and managers to assess their understanding of PRA, the MR, and associated responsibilities.

b. Observations and Findings

The inspectors interviewed the SEs assigned responsibility for SSCs selected, and walked down systems with them. The inspectors noted that the SEs were generally experienced and knowledgeable about their systems. They had received PRA familiarization in risk assessment. The inspectors identified that some of the SEs could not identify the boundaries (i.e., part of systems or components) for the functions scoped into the MR. This was a weakness that could affect the FF determination process for issues identified during performance monitoring. In some cases, SEs exhibited a general lack of knowledge about the application of the MR to their systems. The licensee program previously did not require significant SE responsibility for implementation of the MR, but relied on the SMRO. As a result of the SQV audit, the MR program was revised such that the SEs would assume a larger responsibility with the MR implementation.

c. Conclusions

The inspectors noted that SEs were generally experienced and knowledgeable about their systems; however, they exhibited a limited understanding of the MR. The inspectors also noted that SEs were not actively involved in MR implementation, although the licensee was in the process of increasing the SEs responsibilities with respect to the MR. The lack of understanding SSC function boundaries was a weakness that could affect the functional failure determination process.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors discussed the progress of the inspection with licensee representatives on a daily basis and presented the inspection results to members of licensee management at the conclusion of the inspection on April 15, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary; none was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

* B. Adams, Senior Engineer
  P. Allen, Operations Shift Manager
* E. Ballon, Dresden Acting SMRO
* D. Brindle, Regulatory Assurance Supervisor
* E. Campbell, Maintenance Manager
* R. Colglazier, NRC Coordinator
* R. Deppisch, ISEG Engineer
* E. Fahey, Corporate Maintenance Manager
* R. Gayley, Quad Cities SMRO
* T. Gierich, Operations Manager
* K. Graesser, Byron Site Vice President
* M. Hanneman, Dresden MR Program Improvement Project Manager
* J. Harkness, Site Maintenance Rule Owner (SMRO)
  G. Heesaker, Operations Support Group
  B. Hopkins, Out-of-Service Coordinator
* W. Israel, Site Quality Verification Supervisor
  R. Janowiak, Corporate Staff Structural Engineer
* P. Johnson, Engineering Superintendent
  K. Kofron, Station Manager
* J. Langan, Performance Monitoring Group Lead
* J. O'Connell, Corporate Chief Component Engineer
* K. Passmore, Station Support Engineering Supervisor
  D. Peterson, Operating Experience
  M. Rasmussen, Unit 1 Operating Engineer
* P. Reister, Assistant System Engineering Supervisor
* T. Schuster, Site Quality Verification Director
* M. Sharma, LaSalle SMRO
  P. Shier, Structural Engineer
  C. Sibley, Braidwood SMRO
* M. Snow, Work Control Superintendent
  L. Soth, Senior Staff Engineer PSA
  J. VanLaere, System Engineering Supervisor
  L. Wehner, Operations Unit Supervisor
* C. Wepprecht, Zion SMRO
* D. Wozniak, Site Engineering Manager
* E. Wurz, ISEG Engineer

Westinghouse

N. Closky, Supervising Engineer Reliability & Risk Assessment
J. Lynde, Senior Engineer

NRC

* N. Hilton, Resident Inspector, RIII

* denotes those individuals in attendance at the April 15, 1997 exit meeting.

LIST OF INSPECTION PROCEDURES USED

IP 62706:	Maintenance Rule
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 71707:	Plant Operations

LIST OF ITEMS OPENED

50-454/455/97004-01(DRS)	IFI	Risk Significance of Ventilation Systems
50-454/455/97004-02(DRS)	IFI	Periodic Assessment
50-454/455/97004-03(DRS)	VIO	Reliability Performance Criteria

LIST OF ITEMS CLOSED

50-454/455/97004-04(DRS)	NCV	SQV Audit Findings

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
ATWS	Anticipated Transient Without Scram
BNL	Brookhaven National Laboratory
BOP	Balance-of-Plant
CAR	Corrective Action Report
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
ComEd	Commonwealth Edison Company
CS	Containment Spray
DG	Diesel Generator
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling System
EH	Turbine Electro-Hydraulic Controls
ELU	Electric Lighting Unit
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
ESF	Essential Safety Feature
EWCS	Electronic Work Control System
FF	Functional Failure
FP	Fire Protection
GSEP	Generating Station Emergency Plan
GV	Governor Valve
IA	Instrument Air
IFI	Inspection Follow-up Item
IOE	Industry Operating Experience
IP	Inspection Procedure
IPE	Individual Plant Evaluation
IPEEE	Individual Plant Evaluation of External Events
ISEG	Independent Safety Engineering Group
IV	Intercept Valve
LCO	Limiting Condition for Operation

LIST OF ACRONYMS USED (cont'd)

MEER	Miscellaneous Electrical Equipment Room
MPFF	Maintenance Preventable Functional Failure
MR	Maintenance Rule
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NOV	Notice of Violation
NUMARC	Nuclear Management Resource Council
NR	Neutron Monitoring
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NTS	Nuclear Tracking System
OPEX	Operational Experience
ORAM	On-line Risk Assessment Monitor
PC	Primary Containment
PDR	Public Document Room
PIF	Problem Identification Form
PM	Preventive Maintenance
PORV	Power-Operated Relief Valve
PRA	Probabilistic Risk Assessment
PRT	Plant Response Tree
PSA	Probabilistic Safety Assessment
RAW	Risk Achievement Worth
RCS	Reactor Coolant System
RPS	Reactor Protection System
RRW	Risk Worth Reduction
RSV	Reheat Stop Valve
RWST	Refueling Water Storage Tank
SAC	Station Air Compressor
SE	System Engineer
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SI	Safety Injection
SG	Steam Generator
SMRO	Site Maintenance Rule Owner
SQV	Site Quality Verification
SSC	Structures, Systems or Components
SX	Essential Service Water
TS	Technical Specifications
TV	Throttle Valve
URI	Unresolved Item
VIO	Violation

LIST OF DOCUMENTS REVIEWED

BVP 800-37, "Maintenance Rule Implementation and Compliance Program," Revision 3, March 11, 1997, and Revision 4, April 2, 1997

Individual Plant Examination (IPE) for the Byron Nuclear Generating Station, Units 1 and 2, December 1994

Individual Plant Examination of External Events (IPEEE) for the Byron Nuclear Generating Station, Units 1 and 2, April 1996

NRC Request for Additional Information (RAI) on Byron Nuclear Generating Station, Units 1 and 2 IPE, 1995

Modified IPE for the Byron Nuclear Generating Station, Units 1 and 2, March 27, 1997

Site Policy Memo No. 600.12, "Shutdown Risk Management," Revision 6, February 15, 1996

Site Policy Memo No. 600.13, "On-Line Maintenance," Revision 3, March 21, 1997

NSWP-A-06, "Operating Experience (OPEX)," Revision 0, February 27, 1997

NEP-17-03, "Structures Monitoring," Revision 0, December 31, 1996

QAA 06-97-01, Byron Site Quality Verification Audit of Maintenance Rule, March 1, 1997

Byron Memo BOG-1R06, Attachment I, "Byron Outage Guidelines - B1R06," March 18, 1994

Byron Memo BOG-1F17, "Byron Outage Guidelines - B1F17," February 12, 1997

10 CFR 50.65 - Maintenance Rule Self-Assessment - August/September 1996, September 8, 1996

NUMARC 93-02, "A Report on the Verification and Validation of NUMARC 93-01, Draft Revision 2A, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants"

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