U. S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-454/95011(DRP); 50-455/95011(DRP)

FACILITY

Byron Nuclear Plant, Units 1 & 2
License No. NPF-37; NPF-66

LICENSEE

Commonwealth Edison Company
Opus West III
1400 Opus Place
Downers Grove, IL 60515

DATES

November 7 through December 27, 1995

INSPECTORS

H. Peterson, Senior Resident Inspector
C. H. Brown, Resident Inspector
N. D. Hilton, Resident Inspector
R. Bailey, Reactor Operations Assessment Representative
J. Foster, Emergency Preparedness Inspector
H. Simons, Resident Inspector, LaSalle Station
R. Landsman, Project Engineer
J. Schapker, ISI/IST Inspector
Z. Falevits, Lead Engineering Assessment Program Inspector
G. Cobey, Reactor Engineer
R. Langstaff, Reactor Engineer
J. House, Radiation Protection and Chemistry Inspector
S. Orth, Radiation Protection and Chemistry Inspector
C. Thompson, Illinois Department of Nuclear Safety

APPROVED BY

Lewis F. Miller, Jr., Chief
Reactor Projects Branch 4

1-29-96
Date

AREAS INSPECTED

A routine, unannounced inspection of operations, engineering, maintenance, and plant support was performed. Safety assessment and quality verification activities were routinely evaluated. Specialized inspections were performed in the areas of Radiation Protection, Chemistry, Engineering and Technical Support, Unit 1 steam generator U-tube Eddy Current inspection and repair, and the Byron Station annual emergency preparedness exercise.

RESULTS

Assessment of Performance

OPERATIONS: The inspectors routinely observed professional control room operations and operators continued to demonstrate a questioning attitude concerning special and infrequent plant evolutions. Control room shift briefings continued to be thorough with good involvement by shift personnel. Unit 1 was in Mode 5 (cold shutdown) for a mid-cycle outage during this inspection period. Unit 1 was satisfactorily started up over the Christmas holiday weekend. During the outage, the operators effectively inquired into work and test activities, and monitored plant condition during the extended Mode 5 shutdown operations. During the Unit 1 shutdown, the licensee experienced some problems associated with the nuclear instruments. The problem concerned the simultaneous failure of both source range nuclear instruments during cooldown, which required the entry into the restrictive technical specification requirement to suspend all activities adding positive reactivity. The licensee satisfactorily resolved the issue and met the technical specification requirement. The inspectors identified deficiencies concerning log taking and review of operating parameters during a routine emergency diesel generator monthly surveillance. The log taking deficiency was identified by the inspectors as an inadequate procedure adherence violation.

MAINTENANCE: The licensee's involvement and coordination of routine surveillance and minor maintenance activities were reviewed by the inspectors, and no major concerns were noted. During this period, the Unit 1 mid-cycle outage was conducted to inspect and repair steam generator U-tubes. A total of 764 tubes were plugged and 2055 tubes were sleeved. The next Unit 1 refueling outage was scheduled to commence March 29, 1996. Maintenance activities scheduled during the Unit 1 mid-cycle outage were performed well generally; however, the inspectors had concerns associated with the apparent poor coordination and repair on the auxiliary feedwater valve 1AF013G. The 1AF013G issue was considered an unresolved item pending review of the licensee's corrective actions.

ENGINEERING: The engineering organization appeared to be functioning well with good team work and interface during this inspection period. The licensee's steam generator inspection programs were conservative, and the licensee utilized the plus point probe for more detailed inspection. However, a weakness in reviewing contractor procedures and processes was noted during the tube sleeve welding error. The inadequacies in the contractor's verification process led to seven steam generator tube sleeves being welded twice or welded in the wrong location within the tube. The licensee's trending program on problem identification forms (PIFs), the temporary alteration process, the workaround program, self assessments, and on-site quality verification audits of engineering activities were good. Also, system engineering action to identify the root cause of the emergency diesel generator Agastat relay failures was very good. Specialized engineering training was good. Although Engineering generally performed well, violations of NRC requirements were identified. The inspectors identified design calculation errors which were not identified during the licensee's design

review process. During the Unit 1 steam generator inspection, the licensee identified a missed surveillance which resulted in the failure to plug a U-tube during the last refueling outage. During the licensee's review of the safe shutdown analysis report, in connection with Thermolag resolution, the licensee identified two Appendix R violations concerning the electrical design configuration for the protection of safe shutdown equipment. Subsequent to the licensee's completion of the design review and notification to the NRC, the inspectors questioned the equipment loads on a similarly configured electrical bus. After further review, the licensee found that the bus questioned by the NRC was also a violation of Appendix R requirements. The inspectors identified an example of a violation of inadequate procedure adherence associated with PIF initiation during the review of engineering modification calculations. Also, the inspectors concluded, based on material deficiencies that the inspectors identified, that detailed guidance and expectations were lacking for system engineers on how to conduct system walkdowns to identify equipment deficiencies.

PLANT SUPPORT: The inspectors concluded that the licensee's performance in mitigating the simulated reactor casualty and implementing the emergency plan during the NRC evaluated emergency preparedness exercise was very good. A concern was identified by the inspectors relative to tracking inplant maintenance team activities. The Radiation Protection (RP) department continued to demonstrate strengths in the implementation of the revised 10 CFR Part 20 and the quality of self assessments. In general, RP performance during the mid-cycle outage was good; however, some problems in job planning and communication led to two minor internal contamination uptakes during the steam generator inspection and repair activities. Also, an isolated incident of a worker not having a secondary dosimeter in the Radiological Waste building was identified by the inspectors. The inspectors observed an apparent decline in chemistry performance. Although plant water chemistry and on-site quality verification assessments continued to be excellent, weaknesses were observed in procedure adherence for chemistry sampling and analysis procedures, and chemistry staff self assessment activities. An example of inadequate procedure adherence violation was identified by the inspectors.

SELF ASSESSMENT and QUALITY VERIFICATION: The inspectors concluded that the licensee's self assessment and quality assurance program continued to be effective. The recent on-site quality verification chemistry audit was considered very critical and identified significant issues. The results of the licensee's chemistry audit were comparable with the NRC concerns on declining Chemistry department performance. The licensee's problem identification form (PIF) process was reviewed and the PIF screening meetings appeared to be organized well. A violation of the Technical Specifications concerning Nuclear General Employee Training was identified by the inspectors during the PIF review.

SUMMARY OF OPEN ITEMS

Violations: identified in Sections 3.2, 3.7.3, 5.3, and three examples for one violation (1.6, 3.7.3, 4.4.2)

Unresolved Items: identified in Section 2.2

Inspection Followup Items: identified in Sections 3.6.4, 4.2.3

Non-cited Violations: identified in Sections 3.1.1, 3.1.2, 4.3.2, 4.4.3

SUMMARY OF CLOSED ITEMS

Violations: identified in Sections 1.7.1, 1.7.2

Unresolved Items: identified in Section 3.9.2

Inspection Followup Items: identified in Section 4.5

INSPECTION DETAILS

1.0 OPERATIONS

NRC Inspection Procedure 71707 was used in the performance of an inspection of plant operations. An example of a violation for inadequate procedure adherence was identified (section 1.6).

1.1 Performance of Operations at Power

Unit 2 operated at full power and plant operations were well-managed during this report period. Control room operators demonstrated professionalism and attention to the control room panels. Continued emphasis on three-way communications, safety focus and intra-departmental teamwork was observed. The inspectors determined that the licensee effectively carried out its responsibility to oversee and direct safe plant operations.

1.2 Performance of Operations While Shutdown

Unit 1 was shutdown on October 22, 1995, to perform a 32 day planned mid-cycle maintenance outage for steam generator tube inspection. The unit was scheduled to be returned to service on November 23, 1995; however, due to the significant number of degraded steam generator tubes identified by the licensee, the outage was extended approximately 4 weeks to perform tube repairs. During the mid-cycle outage, conservative operations and questioning attitude were demonstrated by the licensee. The operators routinely asked questions and pointed out concerns during shift and special evolution briefings. Examples included asking questions on special requirements for extended Mode 5 (cold shutdown) operations compared to refueling conditions, and review of precautions and expectations for shutdown operation with both source range nuclear instruments out-of-service. Operators noted that a potential problem could occur during steam generator pressure testing following U-tube repairs. After tube repairs on the A steam generator, air pressurization of the generator was required to test the welds on pulled tubes. A rapid de-pressurization following the test could potentially initiate an inadvertent safety injection signal. Procedural precautions and shift briefings were conducted to prevent the problem from occurring. The inspectors determined that the licensee effectively carried out its responsibility to oversee and direct outage activities.

1.3 Control Room Organization and Observation

Management involvement in control room operations was observed during shift turnovers and reliefs. With one unit shutdown and one unit operating, the shift engineers were conducting frequent tours of the control room observing unit evolutions. During the early portion of 1995, the licensee reorganized the control room manning in response to the NRC violation for the lack of a Senior Reactor Operator (SRO) in the control room (section 1.7.1 describes the violation and its closure). The licensee added an extra SRO, designated as the administrative

Station Control Room Engineer (SCRE). The two SCRE configuration appeared to have improved control room effectiveness. The duty SCRE was now freed from administrative burdens and was able to more effectively concentrate and oversee plant evolutions. This was evident by the apparent decrease in significant personnel errors.

1.4 Unit 1 Mid-cycle Outage

On December 24, 1995, Unit 1 was synchronized to the grid. This ended the 63 days planned mid-cycle steam generator inspection and repair outage. Originally, the outage, which commenced on October 22, 1995, was scheduled for 32 days. However, due to the significant number of degraded steam generator tubes, the outage was extended approximately 4 weeks to perform tube repairs.

The inspectors observed significant portions of the Unit 1 shutdown, startup, and outage evolutions. The licensee experienced several emergent problems during the outage including, both source range nuclear instruments becoming inoperable during shutdown and cooldown (see section 1.5), intermittent failure of emergency diesel generator relays (see section 2.3), and the failure of a charging system valve (see section 2.4). The licensee performed well in coping with these problems. Additionally, the inspectors performed limited walkdowns of safety related systems within the Unit 1 containment during the outage. Examples included portions of the reactor coolant pumps, the reactor coolant piping system, pressurizer system, and emergency core cooling system (ECCS) piping and sump strainers. The inspectors noted material condition inside Unit 1 containment was satisfactory; however, there were many indications of RCS leakage, exhibited by the presence of dry boron deposits on several valves. The licensee adequately repaired and cleaned many valves, including several valves requiring the installation of freeze seals. During the Mode 3 walkdown on December 23-24, 1995, the inspectors noted that the containment material condition was much improved.

1.5 Both Source Range Nuclear Instruments Inoperable

During the Unit 1 mid-cycle outage, the licensee experienced problems with the source range nuclear instruments (NI). Between October 22 and 23, during the process of Unit 1 reactor shutdown and cooldown, source range NI channel N32 was declared inoperable due to suspect faulty indications and channel N31 was later declared inoperable due to NI indications spiking and failing high. Channel N31 failed high and was replaced later in the outage. Channel N32 was repaired, tested, and restored to operable status; however, the two source range channels N31 and N32 were both inoperable for approximately 12 hours. During the 12 hours, the number of minimum operable source range channels (one) as specified in Technical Specification 3/4.3.1 was not being met. Under these conditions, the corresponding technical specification limiting condition for operation (LCO) action statement required all operations involving positive reactivity changes be suspended.

At the time of both NIs being inoperable, the licensee determined the value of the Isothermal Moderator Temperature Coefficient (ITC) was positive. From the positive ITC value, a determination was made that RCS cooldown contributed negative and not positive reactivity. RCS cooldown was adequately performed during the twelve hours when both source range instruments were declared inoperable.

The licensee had previously anticipated this condition of not having both source range NIs operable during a planned maintenance scheduled for the mid-cycle outage, specifically laser cutting inside containment (10 days duration). To prevent potential damage to the NIs during the laser cutting evolution, the licensee had planned to de-energize both source range NIs. To meet and clarify the intent of the technical specification requirement, the licensee performed an On-Site Review (OSR) for operational guidance to allow for RCS temperature control with no NIs operable. However, the situation of both NIs failing during the shutdown and cooldown evolution was not anticipated.

The inspectors determined that the licensee's initial OSR only concentrated on establishing a temperature band to allow for RCS temperature changes. The OSR allowed a temperature band of ±10° F from an equilibrium RCS temperature condition. The licensee's assessment concentrated on the deterministic uncertainties associated with the temperature instruments. A daily order bounding the RCS temperature by ±10° F appeared to allow RCS temperature changes by up to 20° F. The inspectors questioned the licensee on the adequacy of this control band for meeting the Technical Specifications.

The licensee subsequently reviewed the inspector's concerns, and on October 28 completed a new OSR. An evaluation was made to ascertain the temperature effect on reactivity and shutdown margin changes for a positive ITC. The licensee calculated that the change in reactivity for a 5° F increase was insignificant compared to the overall negative reactivity in the core. The overall calculated reactivity change was +30 pcm compared to the total reactivity of -14,398 pcm in the core. The new OSR assessed the effect of temperature change and not just instrumentation uncertainties. Throughout the two time periods with no source range NIs operable (initial cooldown and laser cutting evolution), the licensee satisfactorily maintained RCS equilibrium temperature in the conservative direction (i.e., decreased temperature for positive ITC) meeting the intent of the technical specification for suspending any activities which add positive reactivity. Due to the age of both NIs (over 10 years), the licensee decided to replace both NIs with a new upgraded detectors, including the repaired channel N32. Both source range NIs were satisfactorily replaced during the mid-cycle outage.

1.6 Observation of 1A Emergency Diesel Generator Surveillance

During observation of the monthly surveillance test for the 1A emergency diesel generator (DG), the inspectors noted some discrepancies. A walkdown of the 1A DG on December 7, 1995, revealed some material

condition concerns (section 3.6.4) and a review of the DG operating logs identified concerns regarding log taking. The inspectors identified the following deficiencies associated with log taking practices on the diesel generator operating logs.

- Procedure BOP DG-11T2, "Diesel Generator Operating Logs," Note 1, required the technical staff to be notified if the temperature between any two cylinders exceeded 150°F. On December 7, 1995, with the 1A DG loaded to 2800 KW, the temperature difference between cylinders 8R and 2R was 165°F and 8R and 6L was 160°F. On November 22, 1995, with the 2A DG fully loaded, the temperature difference between cylinders 8R and 10L was 160°F. In both of these cases the operators did not recognize the condition and as a result the technical staff was not notified. This was attributed, in part, to at least one operator being unaware of the existence and the requirements of this note. Also, in the case of the 2A DG, the system engineer had previously reviewed and signed the logs which indicated the conditions; yet, he did not recognize the conditions.

  The most recent Cooper-Bessemer Owner's Group DG Engine Analysis, dated June 1995, indicated that Cooper-Bessemer specified that the ideal cylinder differential temperature limit was 100°F; however, the owner's group engine analysis concluded that a limit of 200°F was considered acceptable.

- The inspectors noted that the operators were not logging the governor oil level accurately. BOP DG-11T2 defined the expected range for the governor oil level as being ± 1/4 inch from the mark on the sight glass. Governor oil level was being logged as "OK" or "SAT" when it was actually out-of-sight high. Subsequent investigation by the inspectors revealed that the oil level was last filled May 31, 1995, and every instance that this parameter had been recorded since was noted as either "OK" or "SAT" when indicated level was out-of-sight high. Based on interviews with equipment operators, the inspectors concluded that this log taking error was due to the operators not understanding the consequences of having too much oil in the system. The licensee's system engineer indicated that too much oil in the governor would cause sluggish operation of the governor. The inspectors concluded that sluggish governor operation could potentially impact the operability of the DG.

The licensee's initial investigation into the inspectors' concerns did not recognize the deficiencies discussed above. The licensee failed to recognize that many of the parameters associated with the operation of the DG were not dependent upon engine loading and that the expected ranges for these parameters were applicable at all times with the DG in operation. Some examples of these parameters included the cylinder differential temperature, fuel oil pressure, lube oil pressure, and governor oil level. Also, their investigation did not recognize the

operator's failure to annotate and disposition out of specification engine parameters.

Following subsequent investigations, the licensee initiated the process of revising the Diesel Generator Operating Logs. Also, the operations department issued a Daily Order on December 19, 1995, to clarify management's expectations for operator performance and documentation.

As a result of the failure of the equipment operators to accurately record the DG governor oil level, the potential existed for the oil level to cause the governor to respond sluggishly and possibly impact the operability of the emergency diesel generator. This was considered an example of a violation of Byron Administrative Procedure, BAP 350-1, "Operating Logs and Records," and of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." (50-454/455-95011-01(DRS))

1.7 Followup on Previously Opened Items A review of previously opened items (violations, unresolved items, and inspection follow-up items) was performed per NRC Inspection Procedure 92901.

1.7.1 (Closed) Violation 454/455-94026-01(DRS): A violation was issued for the failure to maintain a senior reactor operator oversight in the common dual unit control room with a unit at power operations. This occurred over a period of some 22 minutes. This action was contrary to Technical Specification 6.2.2.b and 10 CFR 50.54(m)(2)(iii) which requires a nuclear power unit operating in any mode other than cold shutdown or refueling, as defined by the technical specifications, to have a person holding a senior operator license in the control room at all times.

During the past twelve months, no related problems were noted with operators performing licensed duties. The inspectors reviewed the most current procedural revisions regarding log entries and turnovers, operator training on Technical Specification Section 6, and operator conduct in the common dual unit control room, and found no discrepancies. Following a review of the licensee's corrective actions, this violation was closed.

1.7.2 (Closed) Violation 454/455-94026-02(DRS): A violation was issued for the failure to record in the shift logs the absence of an SRO in the common dual unit for some 22 minutes. This event was a reportable occurrence requiring documentation in accordance with administrative procedures.

During the past twelve months, no additional problems were noted in operators' documentation in the shift logs. The inspectors reviewed the most current procedures and determined that the procedures required a proactive approach to documenting problems. Additionally, the procedures clearly outlines the licensed operators' responsibility in documenting significant events. Following a review of the licensee's corrective actions, this violation was closed.

2.0 MAINTENANCE

NRC Inspection Procedures 62703 and 61726 were used to perform an inspection of maintenance and surveillance activities. During this inspection period, the licensee completed its Unit 1 mid-cycle maintenance outage for steam generator tube inspection. Maintenance activities during the outage appeared to be well performed. The licensee demonstrated good troubleshooting and repair efforts with the charging valve 1CV8105 motor pinion gear and the problem with the Agastat relays in the Diesel Generators. However, the inspectors had some concerns associated with the repair activities for the auxiliary feedwater pump 1B discharge header isolation valve to 1C steam generator (1AF013G). One unresolved item was identified (section 2.2).

2.1 Unit 1 Mid-Cycle Maintenance Outage

Unit 1 was shutdown from October 22 to December 24, 1995, for a mid-cycle maintenance outage for steam generator tube inspection. Originally the outage was scheduled for 32 days; however, due to the significant number of degraded steam generator tubes identified by the licensee, the outage was extended approximately 4 weeks to perform tube repairs. The total number of tubes plugged was 764, and the number of tubes sleeved was 2055. The licensee plans to replace all four Unit 1 steam generators during the refueling outage scheduled to begin January 1999. An inspection on steam generator tube inspection and repair was conducted during the mid-cycle outage (see also paragraph 3.1). A large number of circumferential indications were identified which required repair.

Other major work items completed during the Unit 1 outage included: the second phase of the natural draft cooling tower modification, 10-year inspection of 1A reactor coolant pump motor, inspection of Unit 1 main condenser, and templating the steam generators for replacement generator fabrication. Overall, the Unit 1 mid-cycle outage was managed well with all scheduled maintenance work completed satisfactorily and within the original outage time frame of 32 days.

2.2 Auxiliary Feed Pump 1B Discharge Header Isolation Valve to 1C Steam Generator (1AF013G) Maintenance

The licensee scheduled replacement of internal valve components for motor operated valve (MOV) 1AF013G during the mid-cycle outage due to minor leakage past the valve seats. The licensee's initial plan was to replace the whole valve; however, the scope was changed and only certain internal parts of the valve were replaced. On November 16, 1995, subsequent to valve reassembly and MOV testing, several problems were identified by the licensee, including mechanical damage to the back-seat area of 1AF013G. The inspectors had concerns about stem grease application (mixing two types of grease), problem identification form (PIF) generation (no PIF generated by maintenance on identifying a dissimilar part), and configuration control (wrong part installed into the valve). An investigation by the licensee was in progress at the end

of the report period. This issue was considered an unresolved item pending review of licensee's root cause investigation. (50-454/95011-02)

2.3 Emergency Diesel Generator Agastat Relay Troubleshooting

On November 22, 1995, with Unit 1 in Mode 5 and Unit 2 in Mode 1, the licensee identified a problem with Agastat relays in the Diesel Generators (DG). Over the past year, three relays have failed. The licensee pursued a root cause for the failures. The licensee's laboratory was able to identify a cold soldered joint which would create an intermittent open under certain conditions. The licensee identified the intermittent open during a test which changed the temperature of the relay. All three relays were from the same lot, believed to contain 130 relays. The licensee had 100 relays from this lot installed in three DGs (1A, 2A, and 2B). As a result of the cold solder joint identification, the licensee replaced 26 relays in the 2A DG, ten of which were tested and identified as defective. The discovery of 10 out of 26 relays to be defective caused the licensee to declare the 1A and the 2B DGs inoperable (1A contained 43 of the suspect relays and 2B contained 31). The licensee immediately repaired the relays on the 1A and 2B DGs.

The relays were Agastat EGPDRC relays which provided various control functions to start, run, and shutdown the DGs. The date code of the lot was 9245 (manufactured during week 45 of 1992). The lot was believed to be entirely contained in the licensee's system due to the manufacturing practices of the manufacturer, Amerace. The relays were custom manufactured for a particular purchase order; however, the licensee considered that the nature of the failure indicated a potential process problem during manufacturing.

The licensee demonstrated good troubleshooting and repair efforts, along with good interdepartmental coordination between maintenance and engineering. The licensee also initiated an evaluation for Part 21 applicability.

2.4 Motor Operated Valve (MOV) Motor Pinion Gear Made of Wrong Material

During the first week of the Unit 1 mid-cycle outage, the licensee experienced a reactor coolant system pressure control transient when the charging system flow control valve, 1CV121, de-energized and failed full open during a planned electrical panel outage on 1PA06J, a control cabinet power supply for various control board indications. Details were documented in inspection report 95009. To mitigate the transient, the control room operator attempted to close the charging system downstream isolation valve, 1CV8105. The 1CV8105 valve failed to close. On October 31, the licensee removed the motor on the motor operated valve (MOV) 1CV8105, to investigate the cause of the valve failure.

Maintenance and inspection activities on the valve actuator and motor found the motor pinion gear failed with all the teeth sheared off. The

damage to the valve was confined to the clutch housing near the motor pinion gear. The failed pinion gear induced some damage on the mating worm pinion gear. On November 6, the licensee removed and sent the motor pinion and worm shaft gears to the System Material Analysis Department (SMAD) for analysis. Samples of the failed pinion gear was also sent to the vendor, Limitorque. On December 14, results of the SMAD analysis of the motor pinion gear determined that it was made of 11B44 material, a free machined low grade carbon steel. Limitorque indicated that motor pinion gears for SMB-00 and larger actuators were made from either 86L20, 4140, or 4320 alloy steel. The licensee determined that the failed motor pinion gear was made from an unapproved material which apparently led to the failure of the MOV.

The affected motor pinion gear from 1CV8105 was purchased with the complete operator from Westinghouse, circa 1991. Nine other operators (five at Byron, four at Braidwood) were also purchased at the same time and under the same shop order number. Review of the work history for 1CV8105 indicated that this MOV operator was installed new in 1993. The licensee analyzed 14 replacement gears from the storeroom and seven of the nine gears installed in existing operators. These gears were found to be made of acceptable material. The licensee found only the one original failed pinion gear was bad (wrong material) out of 21 gears analyzed. Based on the low probability of bad pinion gear material, the two remaining pinion gears installed in the operating Byron Unit 2 valves 2CV8105 AND 2CV8106 were placed on the Pre-Authorized Work list to be replaced and tested at the next available shutdown (outage).

The licensee's response to the transient and subsequent troubleshooting, repair, and investigation was very good. Coordination between operations, maintenance, and engineering was also good. The licensee appeared to be very thorough in its testing and analysis of the failed motor pinion gears by identifying the unauthorized material. Although the failed pinion gear appeared to be an isolated case, based on the sampling population of 21 gears analyzed, the licensee initiated an evaluation for Part 21 applicability. The evaluation was scheduled to be completed by January 19, 1996, and any further action was to be conducted by the licensee's Part 21 Technical Issues Committee.

3.0 ENGINEERING

NRC Inspection Procedures 37550, 37551, and 73753 were used to perform an on-site inspection of the engineering function. During the mid-cycle outage, the Unit 1 steam generator U-tube and a specialized engineering and technical support inspections were conducted. Some problems associated with contractor control and control of steam generator inspection data were identified by the licensee.

The inspectors determined that the engineering performance at Byron was very good. The organization was functioning well and exhibited teamwork. The interface within engineering groups and other site organizations was good. Also, the inspectors noted good technical interface between Byron engineering, corporate, other sites, and the Material Distribution Center (C-team).

Examples of good technical interface included the Calculation Metrics Program, the engineering System Readiness Review Board (SRRB), the Technical Review Committee (TRC), and the engineering peer group meetings.

Other good engineering areas included the Temporary Alteration Program, the trending program on Problem Identification Forms (PIFs), the Operator Workaround Program, Material Condition Status Book, System Engineering Performance-Task Tracking System, self-assessments, Support Engineering monthly report, and management involvement in providing system and site engineers with specialized training. Additionally, the licensee's system monitoring and trending activities yielded good results in identifying problematic components, for example diesel generator relay solder joint problem.

Although, the engineering organization performed well, the inspectors had concerns with design changes, calculation errors, and lack of adherence to procedures. Three violations were identified (see sections 3.2 and 3.7.3). Also, there were some areas that appeared to be weak and needed improvement. The following engineering related weaknesses were noted:

- A number of new material condition deficiencies were noted by the NRC inspectors. System engineering had no detailed guidance on how to perform system walkdowns. (section 3.6.4)

- Although a procedure for performing a trend using the PIF process existed, the inspectors concluded that there was no detailed guidance to system engineering on trending. There was no criteria for initiating trends, no identification of critical parameters to trend, and no detailed guidance on assessing the data gathered. (section 3.6.5)

- A number of design calculation errors were noted by the inspectors. The design review process failed to identify these errors. (section 3.7.3)

3.1 Unit 1 Steam Generator (SG) In-Service Inspection (ISI)

Personnel from Westinghouse and ComEd performed the mid-cycle SG inspection in accordance with commitments made to the NRC. A conservative sampling plan which examined tubes with previously reported indications, outer periphery tubing, T-Slot tubes, row 1, 2, and 3 tubes, and preheater section tubes were examined full length with the bobbin coil and Zetec MIZ-18 multi-frequency digital examination equipment. The remaining tubes were examined from the hot leg side to the first support plate on the cold leg side (11C). Special hot leg top-of-tubesheet rotating pancake coil and plus point probe examinations were performed in all SG's. The primary and secondary analysis of the eddy current test (ET) data was performed by Westinghouse. Any discrepancies between the primary and secondary analysis were resolved by an on-site resolution analyst.

A large number of circumferential indications were identified, (in excess of 2000) including a substantial number which were classified as possible circumferential indications (PCI). Due to the large number of circumferential indications and the PCI classification, the licensee utilized two additional eddy current experts from two different contractors (Rockridge and Zetec). These ET experts reviewed the ET data using the Zetec Eddynet 95 software. This software enabled the analyst to eliminate the roll transition signal from the indication more effectively.

A limited amount of data from tubes with circumferential indications at the roll transition using the Plus Point probe was available. There was speculation that some of the small response indications (PCI), may be due to probe lift off, or other anomalies such as scratches in the tube, permeability, or sludge. To provide the needed data, the licensee selected 10 tubes with various sizes of circumferential indications located at the top of the tube sheet for removal and analysis. ET inspection with various probes and ultrasonic examination of the 10 tubes was performed to establish a baseline of data for the indications. Two of the tubes separated at the circumferential indication during removal. These two tubes contained the largest circumferential indications. One tube had the largest circumferential extent and the other tube had circumferential with axial indications (mixed mode). All of the pulled tube lanes were stabilized and plugged.

Due to the large number and size of the circumferential indications the licensee corporate steam generator group plans to review the previous ET data to determine the growth rates of the indications. This data will also be reviewed to determine the adequacy of the previous ET data analysis. The NRC has notified the licensee to provide the time and place of review so that the NRC ET expert inspector could participate in the review. The inspectors considered the SG tube inspection to be good.

3.1.1 Quality Verification for Steam Generator Tubing Repairs (73753)

The SG tube repair processes encountered a number of problems due to the contractors faulty equipment or inadequate procedure adherence. During the sleeve welding process the weld head positioner hardstop slipped, causing the weld to be applied in the wrong location seven times. The seven tubes with misplaced sleeve welds were plugged, five of which were stabilized due to the weld location being off the sleeve. The contractor initiated corrective actions to verify the hardstop set screws were properly located and tightened to prevent slippage. However, this failed to prevent another occurrence of lesser significance, demonstrating the ineffective corrective action previously implemented. Additional corrective actions were taken, including a stop work order by the licensee. Also, training was given to the contractor personnel to ensure the process was controlled.

An example of inadequate inspection requirements occurred in the plug welding visual inspection. The initial visual inspection test of the

plug welding on plug 24-42 in the B SG did not identify a blow-hole which later leaked at static pressure during a leak test. Further evaluation of the original 1X visual examination determined the examination was inadequate to evaluate the weld quality, and an enhanced visual examination (20X) was performed on all the welded plugs. The enhanced visual examination (VT-1) identified two additional suspect defects which were removed and replaced. The licensee identified the VT-1 inspection as inadequate via a VCR tape review, and the contractor's procedures were changed to require the enhanced visual examination.

The licensee identified the inadequacies associated with controlling the contractor procedures and processes, and took the appropriate corrective actions. This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

3.1.2 Missed Surveillance on a Dented Tube

In preparation for the Unit 1 mid-cycle inspection, the licensee identified that during the previous C SG ET inspection, tube row 34 column 14 was not inspected due to an obstruction at the 9th hot leg support plate. During the previous Unit 1 refueling outage, the contractor and licensee engineering failed to identify that the tube with the obstruction had not been examined or identified as a tube which required repair. The obstruction was determined to be a dent exceeding 5 volts, which required rotating pancake coil inspection of the dent (draft Generic Letter on voltage-based plugging criteria) or repair. In addition, Technical Specifications 4.4.5.2.d. requires a 100 percent bobbin coil probe inspection for all hot leg tube support plate intersections and all cold leg intersections down to the lowest cold leg support plate with outer diameter stress corrosion cracking (ODSCC) indications. No further examination or repair of the tube was made. The licensee repaired (plugged) the tube during this mid-cycle outage. The licensee determined the error was due to an oversight of the engineer reviewing the SG inspection data.

The licensee initiated a procedure change to require a thorough review of contractor data base to ensure that all tubes had been inspected by the contractor. This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

3.2 Fire Protection (Appendix R) Discrepancies

On October 10, 1995, the licensee's review of the Safe Shutdown Analysis (SSA) in the Fire Protection Report (FPR) revealed that the analysis conclusions regarding the availability of both Unit 1 and 2 Miscellaneous Electric Equipment Room (MEER) Ventilation Supply Fans for a fire in Fire Zone 11.6-0 (general area of elevation 426 in the Auxiliary Building) were incorrect. On October 12, 1995, the licensee notified the NRC that the condition identified was outside the design

basis of the plant, as required by 10 CFR 50.72(b)(1)(ii)(B). The licensee believed that these two errors were the only discrepancies. Following discussion with and questioning by the inspectors, on October 13, 1995, the licensee was requested to provide the loads on a similarly configured fire zone. Subsequently, the licensee determined that the availability of Unit 1 Division 11 switchgear vent fan and the Division 11 Diesel Generator Fuel Oil Transfer Pump were incorrect in Fire Zone 11.4-0 (general area of elevation 383 in the Auxiliary Building). An update to the NRC notification of October 12 was made on October 13 identifying the additional discrepancy.

The SSA failed to recognize that one 480 Volt ESF switchgear breaker was supplying two 480 Volt motor control centers (MCS). Therefore, a fire that would affect one of the MCCs and trip that breaker, would cause the loss of the other MCC as well. To summarize the four instances described above where a single 480 volt breaker, in the 480 volt ESF Unit Substation buses, supplying two MCC's were:

a. MCC 131X3 and 131X5 were both powered from Bus 131X, compartment 5B. A fire in zone 11.4-0 would result in the loss of both trains of Engineered Safeguard Feature (ESF) switchgear room supply fans (1VX01C and 1VX04C) and both fuel oil transfer pumps for 1A Diesel Generator (DG).

b. Unit 1 MCC 132X4 and 132X5 were both powered from Bus 132X, compartment 5B. A fire in zone 11.6-0 would result in the loss of both trains of MEER fans.

c. Unit 2 MCC 232X4 and 232X5 were both powered from Bus 232X, compartment 5B. A fire in zone 11.6-0 would result in the loss of both trains of MEER fans.

d. MCC 231X3 and 231X5 were both powered from Bus 231X, compartment 5B. There were no redundant equipment cables powered from 231X compartment 5B where both divisions were unprotected in any fire zone.

The licensee also noted other discrepancies during the engineering review to resolve the Thermolag issue. These discrepancies were sections of cabling that were not protected from fire in various fire zones that the cables were routed through. A total of seven previously identified sections of various cables existed. Original identification of the unprotected sections was made during the Thermolag resolution investigation in 1993 and 1994. The sections of unprotected cabling were not considered to be a different problem from the inoperable fire barriers when the discrepancies were originally identified. After additional review in response to the breaker design issues, on October 26, 1995, the licensee determined that these previously identified discrepancies were also reportable to the NRC. A second update to the previous NRC notification of October 12 was made on October 26, 1995.

Immediate and adequate compensatory actions were in place due to previous Thermolag issues, primarily hourly fire watches. Corrective action to power each affected MCC from a separate breaker was estimated by the licensee to be completed by December, 1996. The unprotected sections of cables have been protected or were scheduled to be rerouted.

Appendix R, section III, paragraph G of 10 CFR Part 50 required that fire protection be capable of limiting fire damage so that one train of systems necessary to achieve and maintain hot shutdown conditions was free of fire damage. The arrangement of three breakers described above in cases a, b, and c would not have allowed one train of systems required for safe shutdown of the plant to be free of fire damage. This was a violation of 10 CFR Part 50, Appendix R, section III, paragraph G. (50-454/455-95011-03(DRP))

3.3 Engineering Interface The inspectors attended engineering interface meetings. The licensee had 58 peer groups established to communicate technical issues between ComEd stations. The inspectors noted this was a significant increase in the number of peer groups and considered the groups an improvement in interstation communication.

3.4 Engineering Training The amount of continuing training provided to engineers was good. For example, in 1995, system engineers, on average, attended two courses of specialized training in their respective areas.

3.5 Operability Assessments The inspectors reviewed selected operability assessments. Operability assessments performed by the licensee were generally conservative and well documented.

3.6 System Engineering

The licensee's engineers exhibited ownership and pride in performing their activities. System engineers interviewed were conscientious and knowledgeable of problems in their systems.

3.6.1 System Engineering Performance Monitoring Systems Engineering Department performance windows tool was used by the system engineering supervisor to track and monitor system engineering activities and performance. This was considered a good management initiative to assess performance of system engineers.

3.6.2 System Material Condition Status Reports Engineering System Material Condition Status reports for plant systems provided data relative to design basis, PRA insights, system performance review, maintenance analysis, regulatory analysis design issues, top system concerns/initiatives, and system performance assessment. This was considered a good engineering system report.

3.6.3 Operator Workarounds The inspector reviewed the "Operator Workaround" items identified for the Auxiliary Power and Essential Service Water

systems. The workaround log described the problem, had a detailed action plan to identify corrective actions by a designated system engineer, and included resolution due dates and status of items. The program was well managed and controlled.

3.6.4 Material Condition The material condition of the facility was generally good; however, the inspectors identified several deficiencies that were not previously identified by the licensee. After the deficiencies were brought to the licensee's attention, the licensee took prompt action to evaluate them and initiate appropriate corrective action. No system inoperability was noted. In addition, the licensee initiated several Problem Identification Forms (PIF) to initiate the process of identifying the root cause and corrective action that would prevent the problems from recurring.

The inspectors concluded that the material condition deficiencies identified were examples of deficiencies not adequately identified during the system engineer's walkdown of their assigned systems. System walkdowns were being conducted periodically; however, it was apparent that the quality of these walkdowns varied amongst engineers. This was attributed to the lack of training and detailed guidance on how to conduct system walkdowns. The following were examples of inspector identified material condition deficiencies.

Emergency Diesel Generators (DG) Material condition problems pertaining to the DGs were as follows; the 1B DG exhaust manifold discharged some exhaust gases from the 10R and 10L cylinders into the diesel room during engine startup, the 2B DG intercooler water piping flange was missing one of eight bolts, the 2B DG fuel oil booster relay had an air leak, and the 2B DG fuel oil pressure indication was low. Additionally, lube oil and fuel oil leaks existed on the DGs. Examples of leaks identified included; lube oil leakage on one cylinder head cover, the 2A prelube pump, fuel oil leakage on several of the 2B injection pumps, the 1A fuel oil drain line, and the 2B fuel oil header.

Essential Service Water (SX) Cooling Tower Valve Rooms The inspectors identified what appeared to be localized pitting and corrosion on a circulating water (CW) pipe, the normal make up line to the SX cooling tower. The inspectors questioned if the reduced pipe thickness could be potentially below minimum acceptable wall thickness. The licensee performed an informal non-destructive examination of the pitted area and found that it was below minimum wall thickness. A PIF was generated to repair the pipe, but no immediate operability concern was noted for the SX system. The SX cooling tower receives normal make up water from the CW system; however, the technical specification required make up water supply was from either the deep well pump or the river through the SX diesel driven make up water pump. A loss of the CW system does not affect the operability of the SX tower or the SX system. The licensee has not yet repaired the CW pipe. The licensee was evaluating the extent of what corrective action would be required to assess exterior pipe corrosion for non-safety and safety related systems. This issue was considered an inspection follow up item, pending licensee's

evaluation on other corrective actions for pipe exterior corrosion. (50-454/455-95011-04(DRS)).

Seismic Restraints The inspectors identified numerous seismic restraints (all "U" style supports) that were improperly fastened. For example: the DGs contained several supports that were either loose or missing fasteners on the jacket water cooling system, the starting air system, and the lube oil system; one support for an essential service water line was loose; and the 1B and 2A auxiliary feedwater pump skids contained six supports that were either loose or missing fasteners.

Auxiliary Feedwater (AFW) On December 5, 1995, during walkdowns with the system engineer, the inspector informed the system engineer that terminals 8 and 11 on the battery for Diesel Driven AFW Pump 1B (1AF01EB-B) contained rust. No PIF was initiated until December 18, 1995, after the NRC inspector questioned the system engineer about addressing this problem. The inspector determined that on November 10, 1995, the battery was splashed with SX water from a misaligned funnel under a SX valve packing leak located above the battery. The corrective action to this leak appeared to be ineffective since the terminals became rusted a month later. The failure to initiate a PIF on December 5, 1995, was considered an example of a violation of licensee procedures and of 10 CFR 50, Appendix B, Criterion V (50-454/95011-01)

3.6.5 Engineering Trending The inspectors noted that station procedures existed to require trending activities; however, the quality varied. Procedure BAP 1250-7, "Station Performance Trending," provided guidance for trending events as documented on the PIF to identify repetitive deficiencies. Procedure BAP 1250-2, "Integrated Reporting Program," provided a method using the PIF process for identifying problems and non-conformance, investigating and identifying root causes, and trending data. Also, System Engineering Handbook Memo 900-18 stated that an 18 month PIF trend review should be performed on a system.

Although trending was being performed, the inspectors noted that there was apparently no detailed guidance to system engineering on trending. The inspectors noted that there were no criteria for initiating trends, no identification of critical parameters to trend, and no clear guidance on assessing the data gathered. The quality and extent of initiating trends appeared to vary amongst engineers. The following examples illustrated the range in quality of engineering trends.

Auxiliary Power (AP) System Component Deficiencies

The inspectors determined that in the last several months during Unit 2 refueling and Unit 1 mid-cycle outages (Bus 241 and 143 outages, respectively), greater than expected damaged and failed AP components were noted. Examples included: breaker for essential service water strainer backwash drain valve (1SX150A) was found in intermediate position, the breaker's secondary contact fingers were found sticking; 2A containment spray pump breaker failed to close during testing; and a

Unit Auxiliary Transformer 4 kV breaker failed to close on demand due to a levering in device problem.

The inspectors determined, based on interviews with system engineers and review of documents, that some of the deficiencies encountered were due to a potentially improper method for racking breakers into or out of a cubicle. The inspectors were concerned that other causes for these deficiencies could be due to aging of components or lack of adequate preventive maintenance (PM) activities, which may be related to performance or periodicity of the PM.

To address this concern, the licensee was reviewing PM practices based on evaluation of AP PIFs issued. The PIFs were also being evaluated to determine potential generic implications. In addition, the licensee plans to determine effectiveness of aging strategies from some of the other ComEd plants and adopt the one that might be applicable to Byron. Also, the licensee sent some of the failed components to the Material Distribution Center (C-Team) and System Material Analysis Department (SMAD) for analysis and evaluation. The licensee was to evaluate the results and upgrade the PM program accordingly. The inspectors did not see an immediate concern regarding the noted AP discrepancies and considered licensee actions to address this issue acceptable.

Calibration - Containment Floor Transmitter 2LT-PC006 Failure On December 2, 1995, 2LI-PC006, "Containment Floor Water Level Indicator", was reading higher (8.2 inches) than 2LI-PC007 (0 inches). Subsequently, the licensee determined that an air bubble found in the instrument line for 2LT-PC006 caused this erroneous reading. The inspectors determined that for the last four consecutive calibration checks (performed every 18 months), 2LT-PC006 was found out of calibration and was brought back into calibration each time without performing an evaluation/trending review to determine why the transmitter was found to be out of calibration on consecutive calibration checks. The licensee had not established a formal program to trend calibrations. Subsequently, the licensee provided the inspectors with an outline describing development of a formal comprehensive instrument out-of-tolerance monitoring and trending program.

Diesel Generator (DG) Agastat Relays A good example of a system monitoring and trending activity was the licensee's identification of the DG relay problems. The inspectors determined that the DG system engineer involved in identifying the root cause of the failure of several Agastat type EGPDRC relays to energize during Emergency Diesel Generator surveillances was persistent and thorough in identifying the problem. The cold soldering joints on numerous relays were found deficient. The licensee took prompt corrective action by resoldering approximately 100 affected relays. The inspectors observed the soldering activity and noted good interface with SMAD to determine the root cause of the relay problems.

3.7 Site Engineering The licensee's engineers exhibited ownership and pride in performing their activities. Site engineers interviewed were knowledgeable of design requirements and the modification processes.

3.7.1 Temporary Alterations The inspectors concluded that the licensee's temporary alteration program was a strength. Recently, following an Site Quality Verification (SQV) audit finding, the facility had focused on reducing the number of temporary alterations and ensuring that each temporary alteration had a specific resolution plan. As a result, there were only thirteen temporary alterations installed in the plant, and of those, only five were greater than eighteen months old.

3.7.2 Electrical Load Monitoring System (ELMS) Program Several motor control centers (MCC) tripped on overload at two other ComEd plants due to overloaded MCCs. The inspectors examined Byron's program and administrative controls to control addition of electrical loads to busses over time, to control breaker settings, and technical staff use of ELMS. The licensee load management appeared to be effective in controlling loads on electrical busses. No busses were identified to be overloaded.

3.7.3 Review of Design Changes/Modifications The inspectors examined 14 permanent modifications and nine temporary alterations. In general, the modification packages were well organized and contained the required design documentation, reviews, and approvals. The modification packages adequately documented the work to be done and the post-modification test requirements. The modifications provided an adequate description of the impact of the design changes on the plant and were generally of adequate quality. However, the inspectors were concerned with errors in design calculations performed to support modifications. These calculation errors were identified by the NRC.

Design Calculations During a review of calculations that had been conducted to support modifications, temporary alterations, and operability determinations, the inspectors identified several errors. These deficiencies were not identified and corrected by the licensee during the calculation design review process.

Subsequent to the inspector's identification of the calculation errors, the licensee was in the process of revising the affected calculation errors to demonstrate acceptability. The inspectors determined that the three design calculation errors, listed below, required corrections; however, the significance and overall effect on the system was considered to be small. For example, the calculation errors associated with the modification to the containment recirculation sump isolation valves, calculation BYR95-086, were for a modification that was not yet installed. The three design calculation errors did not effect operability of the components. Furthermore, after the inspector's questions, the licensee reviewed a sample of other calculations performed by the preparer and reviewer and did not identify any additional errors. The following deficiencies were noted:

(1) Calculation BYR95-086, dated October 31, 1995, was to determine maximum differential pressure across the containment recirculation sump isolation valves, SI8811 A/B. The calculation was based on the maximum containment accident pressure, containment flood level at switchover to cold leg recirculation mode, and refueling water storage tank (RWST) head at switchover (Lo-Lo Level).

The calculation contained two non-conservative errors which affected the results. Although the calculation was independently reviewed to verify that the calculation was technically adequate and appropriate for the stated purpose, neither error was identified by the licensee's engineers during the review. As a result of the two errors, the calculation failed to verify the adequacy of design for the modification. The calculation did not adequately determine the maximum differential pressure across the containment sump isolation valves. The two errors were:

- The calculation assumed that there would be no flow in the lines from the RWST to the isolation valves. However, during an accident, considerable flow would exist in the lines due to the suction drawn from several Emergency Core Cooling System pumps. The calculation failed to account for the line losses from the flow which would result in a higher differential pressure across the isolation valves than that calculated.

- The calculation assumed that the minimum RWST level would be at the nominal setpoint for switchover to recirculation mode. However, the use of the nominal setpoint did not account for instrument error. The inspectors noted that the technical specification allowable switchover level setpoint was lower than the nominal setpoint. The inspectors determined that the use of the technical specification allowable switchover level setpoint would have resulted in a higher differential pressure across the isolation valves than that identified by the calculation.

The failure to verify the adequacy of design to account for flow induced line losses due to the operation of Emergency Core Cooling System pumps was considered an example of a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." (50-454/455-95011-05(DRS))

When the inspectors identified the error for the RWST switchover level setpoint, on December 4, 1995, the preparer stated that he was aware of the error. However, no Problem Identification Form (PIF) had been initiated to document the calculation error and the verification failure. Byron Administrative Procedure BAP 1250-2A6, "IRP PIF Threshold," Revision 1, stated that a PIF should be initiated for human performance problems such as independent or dual verification failures. The failure to initiate a PIF in this

instance was considered an example of a violation of licensee procedures and of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." (50-454/455-95011-01(DRS))

(2) Calculation NED-P-BYR-077, dated March 10, 1995, was to determine the minimum thickness of a solid blank to be installed between flanges of the steam generator blowdown system orifice, 2FE-SD033. Two errors were identified:

- The design assumption for the maximum temperature of the steam generator blowdown system was incorrectly listed as 667°F vice 567°F.

- ASME Section III, Division 1, 1974 edition, section NC-3647.2, required that the minimum blank thickness, $t_m = t + A$. Where t was the calculated pressure design thickness and A was the sum of the mechanical allowances for corrosion or erosion, threading and grooving, mechanical strength, and steel casting quality factors. However, the calculation assumed $t_m = t$ and omitted the mechanical allowances factor, A, without providing a technical basis for this omission.

The detailed design review process described in procedure NEP-12-02, "Preparation, Review, and Approval of Calculations," Revision 1, section 5.1.3, required that detailed design reviews shall consist of a review of the calculation for assumptions, appropriateness of analytical methods and judgement, numerical accuracy, completeness, compliance with design criteria, codes, standards, licensing commitments for the adequacy of the design, and reasonableness of output data. As a result of the failure to identify and correct the above deficiencies during the design review process for calculation NED-P-BYR-077, the design verification was considered inadequate and an example of a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." (50-454/455-95011-05(DRS))

(3) Calculation JP-95-263, dated November 21, 1995, was to verify the adequacy of the available suction head for the engine driven jacket water cooling pump and the jacket water circulating pump for the emergency diesel generators. Two errors were identified:

- The jacket water system contained a corrosion inhibitor and a biocide; however, the calculation assumed the system was pure water and did not account for the effects of the two chemicals.

- The net positive suction head was only evaluated for temperatures up to the nominal setpoint for the high temperature alarm and did not account for the jacket water system design temperature.

The licensee's initial operability assessment found the system operable. The licensee was also pursuing the resolution of the jacket water cooling system calculation; therefore, these concerns will be incorporated into the previously opened inspection follow up item 95009-02 (see section 3.9.1).

3.8 Engineering Audits/Surveillances and Self-Assessment

The inspectors reviewed recently completed engineering related audits, surveillances and self assessments. The review was performed to assess their effectiveness in identifying engineering related problems and licensee's corrective action to resolve audit findings. The inspectors determined that the on-site quality verification (SQV) audits of engineering activities were performance based and self-critical with some good engineering related findings. However, assessments of various audit findings in areas such as design control, procedures, and corrective action were not considered in the SQV audit.

The licensee's corporate office had recently started reviewing a sample of calculations performed by the site on a monthly basis to develop a "Calculation Quality" metrics to use as an indicator of engineering performance. The inspectors considered the calculation metrics program concept to be good. However, the results of the program implied that few significant calculation problems existed. This assessment was not consistent with the number of calculation problems identified by the inspectors.

The licensee's May 1995 self-assessment to follow up previously identified weaknesses was good. As a result of the self-assessment, additional management attention and resources were devoted towards the air operated valve program to better address developing issues in that area.

The inspectors determined that, in general, the licensee appeared to provide comprehensive corrective actions to audit findings. However, the responses to significant audit findings did not document root causes for failures.

3.9 Follow-Up on Previously Opened Items

A review of previously opened items (violations, unresolved items, and inspection follow-up items) was performed per NRC Inspection Procedure 92903.

3.9.1 (Open) Inspection Follow-up Item (50-454/455-95009-02(DRP)): Emergency Diesel Generator Jacket Water Standpipe. The inspectors reviewed the supporting documentation for the operability assessment associated with the diesel generator jacket water standpipe in order to ascertain whether it was capable of performing the jacket water system design functions as described in the Diesel Engine Manufacturer's Association Standards and the

Updated Final Safety Analysis Report (UFSAR), Section 9.5.5.2. Calculation JP-95-263, was provided to demonstrate that the jacket water cooling pump had adequate net positive suction head at all times; however, the inspectors had several concerns with this calculation (see section 3.5.3). In addition, the licensee had not addressed the design function of having a sufficient reserve capacity for seven days of continuous operation without makeup. As a result, this issue will remain open pending further evaluation by the licensee.

3.9.2 (Closed) Unresolved Item 50-454/455-94010-06(DRS): A relief valve thrust calculation did not specifically consider thrust due to flow, dynamic load factors, and as built conditions. The licensee has since performed another calculation, which addressed the above issues. The new calculation, which showed that the thrust was less than that originally calculated, was acceptable. This item was considered closed.

4.0 PLANT SUPPORT

NRC Inspection Procedures 71750, 82301, 83750, and 84750 were used to perform an inspection of Plant Support Activities. The licensee continued to perform well in the areas of radiological protection and emergency preparedness. However, some weaknesses were identified in the radiological protection group, but immediate and comprehensive corrective actions were completed. A non-cited violation pertaining to an individual not having a secondary dosimeter while in the radiological waste facility was identified. Chemistry performance was viewed to be weak. The inspectors identified a violation associated with inadequate procedure adherence during chemistry sampling and analysis activities.

4.1 Security & Safeguards

The inspectors noted satisfactory performance of routine items including proper display of photo-identification badges by station personnel, verification vital areas were locked and alarmed, and personnel and packages entering the protected area were adequately searched by appropriate equipment or by hand. Overall, the licensee satisfactorily performed its plant security responsibilities.

4.2 Emergency Preparedness (82301)

An announced, daytime exercise of the licensee's emergency plan was conducted on November 15, 1995. This exercise included the partial participation of the State of Illinois and Ogle county. The exercise demonstrated that the onsite emergency plans were adequate and the licensee was capable of implementing them. The inspectors determined that the licensee's performance was very good.

The performances of State and local response organizations were evaluated by the Federal Emergency Management Agency (FEMA). NRC and FEMA representatives summarized their preliminary findings at a media

briefing at the Ogle County Sheriffs office, Oregon, Illinois on November 17, 1995.

4.2.1 Control Room Simulator (CRS)

The CRS crew was effective in mitigating the emergency preparedness exercise scenario and keeping all personnel informed of the plant (simulator) status. Good use of communication skills and management of personnel were observed. Plant conditions were properly identified and analyzed by the operations crew which contributed to a correct and timely classification of the initial event. The CRS crew identified and recommended the appropriate corrective actions while responding to changing plant conditions. Proper notifications were made to plant personnel.

Frequent crew briefs were held by the Shift Engineer and Shift Control Room Engineer to ensure all personnel were kept aware of current plant status. Appropriate Abnormal Operating Procedures and Emergency Operating Procedures were utilized by the operating crew, which ensured the plant was maintained in an identified and controllable condition.

Operator decorum and communications were excellent, including "repeat backs" of important information so as to preclude misunderstandings.

Classifications and notifications to offsite authorities were made in a timely manner and by the applicable procedure. When it was discovered that the Nuclear Accident Reporting System (NARS) telephone was not working, the commercial backup telephone number was properly used.

Proper corrective actions were proposed and discussed with the Technical Support Center (TSC) following a change in plant conditions. Command and control was effectively transferred to the TSC in a timely manner and made known to the crew.

The inspectors concluded that the overall performance in the simulator control room was excellent.

4.2.2 Technical Support Center (TSC)

Activation and staffing of the TSC was accomplished in a timely and orderly manner. Extensive and appropriate utilization of procedures was observed. The Station Director demonstrated excellent Command and Control of the facility, effectively guiding the TSC staff in their response to the emergency.

Periodic briefings of the TSC staff were excellent. The Station Director would provide an overview, then group directors would provide additional details. A "Notification Summary" status board was effectively utilized to track times for notifications, state updates, and TSC staff briefings.

A new "flip chart" was very effectively utilized to display the current Emergency Action Level, and the conditions which would require escalation to the next Emergency Action level.

Field monitoring teams were dispatched and directed by the TSC while the facility was in Command and Control of the response to the emergency. Field monitoring teams were dispatched well before the radioactive release and well positioned in the potential plume pathway. Meteorological forecasts were obtained and posted.

Event classifications and notifications were made in a correct and timely manner. TSC personnel also properly recommended escalation to the General Emergency classification when scenario conditions warranted this classification. The staff demonstrated a good understanding of the status of the fission product barriers. Protective actions recommendations were made using the relevant procedure.

Following the Site Area Emergency declaration, TSC staff were aware of the requirement to evacuate non-essential plant personnel from the site. Weather and road conditions, as well as the potential radioactive plume pathway, were properly assessed as a part of the evacuation strategy.

Technical and operational analysis of reactor conditions was very good. Attempts were made to locate the initial leak by sequentially isolating systems. An excellent discussion was held on the relative merits of reestablishing charging flow or allowing the Safety Injection to occur automatically.

There were difficulties in assessing the probable amount of fuel clad or fuel damage. There were two different methodologies useable for such analysis, with considerably different assumptions. Discussion with licensee personnel indicated that core damage assessment methodology will be reviewed.

Transfer of Command and Control to the Corporate Emergency Operations Facility (CEOF) was smooth and efficient. The TSC properly retained responsibility for communications with the NRC over the Emergency Notification System line, and control of offsite monitoring teams.

The inspectors concluded that overall performance in the TSC was very good.

4.2.3 Operational Support Center (OSC)

The OSC was activated in an efficient manner and functioned well. Initial briefings were good, and the quality of the briefings improved as the exercise progressed. There was no initial, formal announcement of who had the lead in the OSC, but this was later rectified.

A new board in the OSC provided for a listing of available personnel by discipline. This board provided immediate recognition of need for additional personnel in various specialties. Magnetized cards were

moved to a team tracking board when one of the available personnel was assigned to an inplant team.

The assembling, briefing, dispatching, and debriefing of Emergency Teams were performed well. Team briefings emphasized the need for personal safety and maintaining low radiation exposures, the use of proper protective equipment, the expected routes of travel and activities, and the reporting back of any unusual findings. Dosimetry was efficiently issued. One inplant team was accompanied by the inspectors. The team received good support from the accompanying health physics technician.

Overall performance in the OSC was considered good; however, the inspectors noted that a personnel hatch repair team was going back out into the plant without the knowledge of TSC personnel. At another point, the TSC Station Director ordered work on the personnel hatch outer door to be halted. This direction was passed on to the personnel hatch outer door inplant team without the immediate knowledge of the OSC Director. Based on these examples, the inspectors determined that not all of the inplant teams dispatched by the OSC were known in the TSC. A status board in the TSC and OSC tracked major priorities and teams associated with those priorities, including, where appropriate, estimated times of task completion. However, the above examples demonstrated that a team might be redispatched into the plant without clearly associated with a major priority, or could be dispatched by the OSC Director without the cognizance of the Station Director in the TSC. Actions taken to assess the licensee's review of the process for tracking and directing inplant teams will be tracked as an inspection followup item. (50-454/455-95011-06(DRS))

4.2.4 Emergency Operations Facility (EOF)

The EOF staff performed all required functions very well while being in command and control of the simulated emergency. Communications and information flow between the EOF and other facilities were good. Notifications to offsite authorities were timely. The transfer of command and control to the EOF from the CEOF was smooth and orderly. The Environmental Director was aggressive in taking over field team control from the TSC. On the other hand, the Manager of Emergency Operations (MEO) was less aggressive and took about 50 minutes, from the time minimum staffing was achieved, to take over command and control.

An overhead projector was utilized to display a simplified drawing of the radioactive material release path. This provided a clear understanding of the release path for individuals unfamiliar with plant systems. Status boards were well utilized and maintained. Priorities for mitigation of the accident and significant events were well tracked.

Illinois Department of Nuclear Safety (IDNS) was contacted, and licensee effluent release readings were compared to readings obtained from IDNS monitors. Dose calculations were properly performed, and back calculations from field team data were performed to estimate the

radioactive material release rate. Throughout the simulated event, the protective measures staff did a very good job assessing the potential release pathways, field team measurements, and dose assessments.

Protective Action Recommendations (PARs) were properly made per the proceduralized flowchart. On the declaration of a General Emergency, the default PAR (evacuate 2 miles, shelter the three downwind sectors, and shelter 5-10 miles) was issued. Notifications and updates to offsite agencies were timely.

An internal communication problem within the EOF delayed an upgrade to the initial PAR (to Evacuate 2 miles radially, evacuate three downwind sectors 2-5 miles, and shelter 5-10 miles) for approximately 20 minutes. The Environmental Emergency Coordinator (EEC) had discussed the need to upgrade the PAR with the Protective Measures Director (PMD). From these discussions the EEC intended that the PMD recommend the upgrade in the PAR to the MEO. Even though the upgrade was delayed, it had no practical effect on the offsite response or evacuation.

Discussion with the MEO regarding issuance of potassium iodide (KI) for field monitoring team personnel should have had a more detailed review by the MEO. The recommendation was that field teams be issued KI, and the MEO approved KI for "all onsite personnel".

The inspectors concluded that the overall performance in the EOF was good.

4.2.5 Exercise Control and Critiques (IP 82301)

The inspectors concluded that the licensee had a sufficient number of personnel to effectively control the exercise. Minor scenario problems were quickly identified and rectified by the exercise controller organization. No significant examples of controllers prompting participants to initiate actions were identified.

Critiques were held in each facility following the exercise. The inspectors determined that facility critiques appeared weak, in that few exercise participants provided verbal comments (either positive or negative), suggestions, or recommendations for improvement. However, exercise participants were provided with comment sheets. A review of completed comment sheets indicated that a spectrum of critical comments were received.

4.3 Radiological Controls (83750 and 84750)

Implementation of the revision to 10 CFR 20 was a strength. However, a lack of coordination and planning was observed during radiological waste activities. Additional weaknesses in communication and planning were identified by the licensee which resulted in unplanned worker uptakes of radioactive material during steam generator repair evolutions.

4.3.1 Implementation of the Revised 10 CFR Part 20

The licensee effectively implemented the January 1, 1994 revision to 10 CFR Part 20. Procedures were implemented and revised to meet the requirements for the control and posting of high and very high radiation areas (HRAs and VHRAs) and control of planned special exposures (PSEs). Procedures and training which implemented the fetal protection program (declared pregnant women (DPW)) appeared to be well understood by licensee personnel. The licensee also performed a corporate self assessment which provided a good review of the licensee's compliance with the revised rule.

The licensee implemented strong controls for VHRAs and PSEs. Procedure BAP 1450-2, "Control of Access to High Radiation Areas, Locked High Radiation Areas, >15,000 mrem/h Areas and Very High Radiation Areas," revision 8, required approval of the station manager and radiation protection supervisor (RPS) for entry into VHRAs. Additionally, potential VHRAs were secured with unique locks, which required two unique keys, each controlled only by the station manager and RPS. PSEs were controlled by procedure BRP 5300-2, "Exposure Review and Authorization," revision 4, which required approval by the licensee's site vice president and other station management for a person to receive a PSE.

The licensee's design and implementation of its DPW program was excellent. The licensee's procedures BRP 5300-3, "Administration of the Radiation Protection Aspects of ComEd's Fetal Protection and Postnatal Programs," revision 4, and BRP 5300-5, "Special Instructions Concerning Female Radiation Workers," revision 4, implemented the requirements of 10 CFR Part 20 for the control of dose to an embryo/fetus and provided additional provisions for women intending to become pregnant. The inspectors interviewed a random selection of licensee female personnel who appeared to have a good understanding of the licensee's DPW program, NRC requirements, and licensee contacts for additional information. Licensee personnel understood the voluntary nature of the declaration of pregnancy and the provision for withdrawing a declaration of pregnancy. The inspectors reviewed the dose evaluations of DPWs since the implementation of the program and found that doses to DPWs were reviewed on a weekly basis and were well below the licensee's administrative levels.

Overall, the licensee's programs and procedures implementing the revised 10 CFR Part 20 were excellent.

4.3.2 Coordination and Planning of Radioactive Waste Activities

The coordination and planning of radioactive waste (radwaste) activities appeared weak. The inspectors observed problems leading to the packaging and shipping of a radwaste liner. Prior to loading the empty container, licensee personnel (i.e. a contractor, an operator, and station laborer) removed an overpack via the radwaste crane. Because of their unfamiliarity with the specific container design, the individuals

had to re-position the overpack on the vehicle to provide an area to store the container's lid, which required additional time in the area and indicated a lack of pre-planning. Once the empty container was opened and prior to a radiological survey of the internals, the contractor and station laborer began inspecting the container internals. Although no radiological problems were found during subsequent surveys by the radiation protection technician (RPT) providing continuous coverage, the radiological conditions were not known prior to the contractor's inspection of the container internals. Prior to loading the radwaste liner, the RPT stopped the progress of the evolution to evaluate the radiological conditions of the radwaste liner and the applicable radiological postings and controls. This action appeared to indicate a lack of pre-planning for the evolution.

The inspectors noted that one of the individuals did not have a secondary dosimeter. Once identified by the NRC, the RPT removed the individual from the area and notified the RPS. Following the evolution, the licensee implemented corrective actions including training of the individual, instructions to the individual's unit by the individual, and added management oversight of the radwaste radiologically posted areas. The failure to have a secondary dosimeter was a violation of the licensee's procedure BRP 5000-7, "Unescorted Access to and Conduct in Radiologically Posted Areas." This failure to have a secondary dosimeter constituted a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.

4.3.3 Self Assessment of Unplanned Uptakes of Radioactive Material During Steam Generator Repair Evolutions

The licensee identified problems in job planning and communication concerning steam generator (SG) sleeving evolutions performed on December 9 and 10, 1995. During the evolution, two individuals became internally contaminated. The NRC performed confirmatory dose assessments from whole body counts which were in good agreement with the licensee's assessment. The dose assessments indicated that doses (committed effected dose equivalent) to the individuals were about 10 and 80 millirem (0.1 and 0.8 millisievert). Although one of the contaminations appeared to result from an accidental brushing of the surface, the other individual's contamination resulted from poor work practices. Prior to the implementation of interim corrective actions, the licensee suspended all SG jumping activities. The licensee's investigation was very thorough, and the licensee corrective actions appeared to address the root cause of the events.

The licensee's preliminary investigation indicated weaknesses in the pre-job briefing and the communications between the work groups. After vacuuming the SG bowl, the contractor, performing a cleanliness inspection, requested a cloth for wiping the bowl. The RPT assigned to SG sleeving evolutions allowed the cloth but instructed the individual that it was to be wetted during use. While wiping down the SG bowl, the contractor used a dry cloth, which apparently resulted in the internal

contamination. During the investigation, the licensee identified that wiping of the SG bowl was not addressed during the pre-job brief nor was the RPT in attendance at the pre-job briefing. Emphasizing the importance of content and attendance at pre-job briefings, the licensee's interim corrective actions required attendance at pre-job briefings by all working groups and additional pre-job briefings if job scope or participants changed.

The licensee's preliminary assessment of the evolution was very comprehensive. The licensee appeared to address the identified weaknesses concerning the planning of the evolution and communications between the radiation protection and contract groups and to develop comprehensive corrective actions.

4.4 Chemistry (IP 84750)

Management oversight of the chemistry program appeared weak. Although site quality verification (SQV) assessments were a strength, chemistry observations and findings indicated pervasive weaknesses in laboratory quality assurance, procedural adherence and adequacy, and post accident sampling quality control. The chemistry self assessment program was weak in identifying program deficiencies to chemistry senior management. Additionally, a violation was identified for NRC observations of inadequate chemistry sampling activities.

4.4.1 Water Chemistry Control Program

The licensee maintained a strong water chemistry control program. A review of selected trend records covering the past 12 months indicated that plant water quality was excellent. Primary coolant sulfate (both units) was 1 part per billion (ppb) or less, dissolved oxygen was less than 1 ppb (both units). Unit 2 chloride was 1 ppb or less; Unit 1 chloride was approximately 5 ppb following the fall 1994 outage, but dropped to less than 1 ppb. Primary coolant isotopic analyses did not indicate any fuel problems.

Unit 1 SG blowdown data for the first quarter of 1995 showed good cleanup following the massive intrusion of raw water into the SGs following the condenser tube break in December of 1994. SG blowdown contaminants (Unit 1) for the remaining three quarters had returned to the low levels normally seen. The licensee's performance in recovering from this intrusion was very good. SG blowdown parameters (Unit 1) were 2 ppb or less for chloride and less than 3 ppb for sulfate following the cleanup. Unit 2 chloride was less than 1 ppb and sulfate was 1-2 ppb. Sodium for both units was less than 1 ppb for both units.

Continued improvement in secondary system chemistry was evidenced by the conversion from ethanolamine to methoxypropyl amine (MPA) for SG pH control in order to reduce iron transport.

4.4.2 Chemistry Sampling Techniques and Procedural Adherence

The inspectors identified weaknesses in analytical sampling techniques and procedural adherence violations. The inspectors observed chemistry technicians (CTs) performing routine sampling of reactor coolant on November 14 and 17 and found problems concerning procedural adherence and analytical techniques. The following examples of inadequate procedural adherence were observed:

a. On November 14, the CT collected the samples in re-used sample containers. However, the CT did not rinse the sample containers with the sample stream to eliminate chemical contamination in accordance with BCP 300-2, "General Sampling Procedure," revision 6. The failure to pre-rinse the container increased the potential for chemical contamination.

b. On November 17, the CT failed to perform a radiological survey of the liquid sample panel as required by BCP 300-23, "Reactor Coolant or Pressurizer Liquid Grab Sample," revision 10.

c. On November 17, the CT measured the dissolved oxygen of the primary system with a testing kit which did not give accurate indication at the range of the system as required by procedure BCP 100-39, "Determination of Analytes using a Chemet Test Kit," revision 1. The CT utilized a 0 - 1 part per million test kit instead of the 0 - 20 parts per billion for a measurement in the part per billion range.

Although one of the CTs surveyed the liquid sample panel after sampling as required by BCP 300-23, neither CT surveyed the panel prior to sampling to ensure no change in the radiological conditions.

Technical Specification 6.8.1, in part, requires the implementation of procedures recommended in Appendix A of Regulatory Guide 1.33, revision 2. Chemistry procedures BCP 300-2, BCP-300-23, and BCP 100-39 implement the chemistry sampling and analysis procedures recommended in Appendix A of Regulatory Guide 1.33. The failure to follow station chemistry procedures was an example of a violation of Technical Specification 6.8.1 and of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." (50-454/455-95011-01(DRS))

4.4.3 Quality Assurance (QA) Assessments

Overall, assessments of the chemistry performed by the site quality verification (SQV) were excellent. The SQV program for chemistry was comprehensive and emphasized chemistry operations. The recent chemistry audit demonstrated that the SQV group understood the purpose of the chemistry program and had evaluated both analytical and operational performance. The audit included reviews of sample acquisition, preparation and analysis, technician performance, in-line monitor performance, laboratory quality assurance, and procedure adherence and adequacy. The self assessment program was performance based and

auditors accompanied chemistry personnel during the discharge of their assigned responsibilities. The SQV program for chemistry was a strength and had identified weaknesses in the chemistry program.

During the audit, the SQV team identified a number of weaknesses in the chemistry area concerning procedural adherence and a major weakness with the high radiation sampling system (HRSS) quality control program. From late July into early October of 1995, the routine quality control program (performance checks) for HRSS instrumentation had not been performed, and the instrumentation had not been declared out of service. However, the sampling systems were operational and exercised as part of the routine sample collection process. Following the discovery by SQV, the licensee declared the instrumentation out of service, completed the performance checks of the in-line instrumentation, and instructed the chemistry staff on the importance of HRSS quality control. During additional discussions with the chemistry supervisor, the inspectors were informed that the quality control chemist was aware of some of the problems concerning the in-line HRSS quality control implementation, but did not adequately implement actions to correct the quality control problems. The inspectors determined that the lack of quality control for the HRSS was a weakness in the chemistry self assessment program.

The failure to perform the HRSS performance checks was a violation of chemistry procedures BAP 560-10, "Byron Chemistry Post-Accident Program Description", Revision 1, and BCP 310-1, "Performance Check Schedule", Revision 9; however, the inspectors determined that the licensee implemented prompt and adequate corrective actions. This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

The inspectors reviewed a number of problem identification forms (PIFs), which described incidents caused by personnel errors and communication problems. These problems, along with the procedural compliance issues discussed in Section 4.4.2 appeared to indicate to the inspectors that there were weaknesses in the performance of the Chemistry Department.

4.5 Followup on Previously Opened Items

A review of previously opened items (violations, unresolved items, and inspection follow-up items) was performed per NRC Inspection Procedure 92904.

(Closed) Inspection Followup Item No. 50-454/94008-01; 455/94008-01: During the 1994 exercise, a concern was identified relative to the inability to demonstrate the use of the Corporate Emergency Operations Facility (CEOF) as an interim Emergency Operations Facility (EOF). The CEOF functioned very well during the 1995 annual emergency preparedness exercise. This item was considered closed.

5.0 SELF ASSESSMENT/QUALITY VERIFICATION (40500)

The inspectors continued to evaluate the effectiveness of the licensee's self assessment and quality assurance programs. During this report period the inspectors focused on determining whether technical resolution of a sample of Problem Identification Forms (PIFs) was adequate to correct and prevent the problems from reoccurring.

5.1 There appears to be a trend in not complying with technical specification requirements in the operating department during the last cycle. The licensee did an investigation into operating events that involved errors in technical specification compliance since the last startup and determined that most errors occurred in the area of knowledge and skills. In particular, the errors were due to inadequate job skills, work practices, decision making, or not performing verifications. They indicated that operators were not checking the information they use to perform their jobs. They were taking action without assessing the situation. All shift personnel were given training on methods for qualifying, validating, and verifying information received. Refresher training on self checking and the STAR (Stop, Think, Act, Review) program was also included. The training was completed during the last quarter of 1995. The training appeared appropriate for the identified concerns.

5.2 The centrifugal charging pump (CV) seals have leakage greater than allowed in the UFSAR during normal plant operation. The licensee stated that the leakage was of concern only after a loss of coolant accident (LOCA) because of the possible radiological consequences from contaminated RCS water. Initially the evaluation appeared to ignore the problem; however, discussions with cognizant individuals indicated that the CP seals are an industry wide problem. The seals have random intermittent leakage during all conditions (shutdown and operating). Apparently, the seals need to be run in to stop the leakage, usually up to 3-4 hours. Seals are replaced when a steady stream of water was evident for 2-3 weeks. The licensee was actively involved with various owner's groups on solving this problem. The amount of leakage has been reduced through the years by better seals and alignment techniques. The plant was currently installing covers over the seals to limit spray if and when it occurs.

Even though the PIF response seemed to not address the concern, the problem was receiving the right amount of licensee attention.

5.3 A contract employee was authorized access to radiologically controlled areas of the plant without proper training. The licensee reviewed the circumstances surrounding the incident and determined that in August 1994, the Byron Training Department was notified by System Engineering that a vendor technician required access to the Radiologically Controlled Area (RCA) to perform 4 hours of maintenance on laundry equipment. The vendor's Nuclear General Employee Training (NGET) had expired. The initial NGET course (12 hours of instruction) was required for anyone who did not have current NGET. However, an instructor made

plans to provide a challenge exam to the vendor although a challenge exam was only allowed for persons with current NGET. The cost of training the vendor was a factor in this decision.

On August 30, 1994, the vendor arrived on site. A second instructor learned that a challenge exam was being offered and advised his supervisor, the Technical Lead Group Leader (TLGL), that a challenge exam could not be given under the current procedure. The instructor also expressed concern that the potential existed for the vendor to subsequently access any ComEd nuclear facility without having approved training. However, the TLGL then directed the first instructor to give abbreviated training and administer the challenge exam to the vendor. The vendor passed the challenge exam and was issued an NGET card. He then performed the maintenance while escorted and left the site with the NGET card in his possession.

Byron Technical Specifications required that procedures be established, implemented, and maintained covering personnel radiation protection, especially procedures for training on radiation protection. Byron Training Procedure BTP 300-5, "Nuclear General Employee Training," stated that initial NGET was required for persons not having current NGET. Additionally, the procedure stated that challenge NGET was for persons having current NGET. ComEd corporate NGET procedures stated that under "urgent circumstances" personnel may be exempted from NGET and be allowed escorted access only with Health Physics Supervisor (HPS) authorization. The procedure also stated that a NGET card should not be issued when using this option.

On August 30, 1994, under normal plant conditions, and with the HPS not authorizing it, (in fact the HPS conveyed that the contractor should have NGET), the TLGL directed that the contractor be given a challenge exam and be issued a NGET card, even though members of his staff expressed concern over non-compliance with site procedures. This failure to follow site NGET procedures was a violation of technical specifications and station procedures. (50-454/455-95011-07(DRP))

The inspectors concluded that the initial stated PIF screening meeting comments listed on the PIFs were sometimes too brief. This lack of detail that may have gone into making the decision might leave the originator with the impression that their issue wasn't given the proper amount of attention. Regulatory assurance personnel agreed with the inspector's observation and stated that they would attempt to communicate the PIF results to the originator more effectively.

6.0 PERSONS CONTACTED AND MANAGEMENT MEETINGS

6.1 On November 22, 1995, Mr. M. J. Farber, Acting Chief Branch 4, Division of Reactor Projects, toured the Byron plant and met with licensee management to discuss plant performance and evaluations.

On December 12 and 13, 1995, Messrs. G. Grant, Division Director, Division of Reactor Safety, G. Wright, Acting Deputy Division Director,

Division of Reactor Projects, and R. Capra, Director, Project Directorate III-2, Division of Reactor Projects NRR, toured the Byron plant and met with licensee management to discuss plant performance and evaluations. This was a mid-SALP senior management visit.

6.2 The inspectors contacted various licensee operations, maintenance, engineering, and plant support personnel throughout the inspection period. Senior personnel are listed below.

At the conclusion of the Chemistry and Radiation Protection inspection and the Emergency Exercise inspection, on November 17, 1995, the inspectors met with licensee representatives (denoted by *) and summarized the scope and findings of the inspection activities. The licensee did not identify any of the documents or processes reviewed by the inspectors as proprietary.

On December 21, 1995, at the conclusion of the routine resident, Engineering and Technical Support, and Steam Generator inspections, the inspectors met with licensee representatives (denoted by #) and summarized the scope and findings of the inspection activities. Additionally, the resident inspectors met with licensee representatives (denoted by @) on December 27, 1995, to close the inspection period and cover the Unit 1 restart after the mid-cycle maintenance outage. The licensee did not identify any of the documents or processes reviewed by the inspectors as proprietary.

\# K. Graesser, Site Vice President
*#@ K. Kofron, Station Manager
#@ D. Wozniak, Site Engineering Manager
* @ T. Gierich, Operations Manager
*# P. Johnson, Technical Service Superintendent
#@ E. Campbell, Maintenance Superintendent
*# M. Snow, Work Control Superintendent
\# D. Brindle, Regulatory Assurance Supervisor
\# A. Javorik, Technical Staff Supervisor
\# T. Higgins, Support Services Director
\# K. Passmore, Station Support & Engineering Supervisor
\# T. Schuster, Site Quality Verification Director
*#@ R. Colglazier, NRC Coordinator
* R. Gossman, Chemistry Supervisor
\# R. Wegner, Shift Operations Supervisor
#@ W. Kouba, Long Range Work Control Superintendent
* W. McNeill, Generating Station Emergency Preparedness Coordinator
* L. Bushman, Lead ALARA/Operation HP
* M. Marchionda, Lead HP
* D. Olsen, Chemistry Lab Supervisor
* W. Conti, Chemistry Lab Supervisor
\# J. Langan, Performance Monitoring Group Leader, System Engineering
\# J. Feimster, Mechanical Lead, Station Support, Site Engineering
\# M. Leutloff, Mechanical Lead, Mod Design, Site Engineering
\# B. Adams, Site Engineering
\# B. Jacobs, Electrical Lead, Mod Design, Site Engineering

R. Freidel, Site Quality Verification
B. Branson, Site Quality Verification
W. Grundmann, Aux System Group Leader, System Engineering
D. Spitzer, Electrical Group Leader, System Engineering
J. VanLaere, Assistant System Engineering Supervisor