U.S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-315/96004; 50-316/96004

FACILITY

Donald C. Cook Nuclear Generating Plant

LICENSEE

Indiana Michigan Power Company
Donald C. Cook Nuclear Generating Plant
1 Riverside Plaza
Columbus, OH 43216

DATES

February 27, 1996 through April 8, 1996

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5/17/96
Date

AREAS INSPECTED

A routine, unannounced inspection of operations, maintenance, engineering, preparation for refueling, plant support, and review of UFSAR commitments was performed. Safety assessment and quality verification activities were routinely evaluated. Follow-up inspection was also performed for non-routine events.

Executive Summary

OPERATIONS

The inspectors continue to identify problems with the control and use of procedures and instructions. Two of the following examples identified during this inspection period pertained to non-routine plant evolutions:

- Operators verbatim complied to a procedure for a non-routine plant evolution, even though there was a known operator workaround that resulted in immediately deviating from the procedure (Section 1.2).

- Procedures for a reactor shutdown and technical specification surveillance were revised utilizing the temporary change process, even though the revisions changed the intent of the approved procedures (Section 1.3.1).

- An approved process allowed written guidance to be provided to the operators that was outside of plant procedures. The process did not ensure that the additional guidance was evaluated for the introduction of an unreviewed safety question (Section 1.3.2).

The following operator workarounds were not identified by the licensee:

- During the non-routine evolution of removing the Unit 2 normal chemical and volume control system (CVCS) letdown flow path from service, the operators had to quickly reopen the letdown containment isolation valves to prevent lifting of a safety relief valve, due to known leakby of upstream valves (Section 1.2).

- The automatic design feature of the condensate booster pumps' minimum control flow valves is procedurally defeated during plant operations due to the discharge line of the CBPs being 20" in diameter and the minimum flow line being 10" line (Section 3.3).

MAINTENANCE

FME controls around the fuel handling areas, general containment cleanliness, and housekeeping were excellent. Licensee management made regular tours of containment and the fuel handling areas and prompt action was taken to correct any identified discrepancies (Section 1.4.2).

There were missed opportunities to ensure that the installation of a containment jig crane while the unit was at power was properly performed. The missed opportunities consisted of: 1) Workers not being attentive for possible interferences during initial rotational checks of the jig crane and 2) the jig crane was not thoroughly inspected following inadvertent damage to the crane (Section 2.2).

ENGINEERING

A review of the technical specification (TS) surveillances for the ice condenser identified the following concerns (Section 3.1):

- The system engineer believed that the allowable ice condenser bypass was 50 ft^2, rather than the allowable 5 ft^2 (Section 3.1).
- No tracking mechanism existed to ensure the 5 ft^2 design limit was not exceeded (Section 3.2).

PLANT SUPPORT

Radiological Controls (Section 4.1)

- Implementation of radiological controls during the Unit 2 refueling outage were characterized by good RP controls and careful radiological work practices.
- Source term exposure efforts continued to be successful in reducing radiation exposure.
- Concerns were raised about workers loitering in the upper containment during ongoing outage activities.
- A tour of the auxiliary and turbine buildings showed good radiological housekeeping and worker RP awareness.

Control and Review of Water Chemistry (Section 4.1.3)

- Contaminants in plant water systems were generally controlled at or below the licensee's aggressive goals.
- Periodically elevated chemistry contaminants were attributable to oxygen inleakage into the condensate system and the limited capacity of the RO system.
- Some weaknesses in chemistry technician (CT) performance were observed, which was inconsistent with management's expectations.

Post Accident Sampling System (PASS) (Section 4.1.5)

Based on the IPAP inspection, a violation was issued for failure to perform PASS QC activities in accordance with procedures. During this inspection, the inspectors identified that a CT had difficulty in operating the PASS in accordance with chemistry procedures.

Chemistry Laboratory Quality Control (QC) (Section 4.1.6)

- Problems were identified with procedural adherence and supervisory review of QC data.

- Inconsistencies were identified concerning the application of the QC program, which may decrease the overall effectiveness of the program.

Emergency Preparedness (EP) Program (Section 4.2)

- To enhance the effectiveness of the EP program, a new offsite EOF/JPIC facility has been purchased and will be remodeled (Section 4.2.3).

- Procedures/drills for offsite communication of Protective Action Recommendations (PARs) were weak in that a key EP director had never had the opportunity to exercise his responsibility for this function (Section 4.2.5).

- Although identified in previous actions, training was not updated with information on NRC and DOE response practices and operational concepts for key incident response personnel. Additionally, confusion over initial PARs has not been resolved (Section 5.0).

Security (Section 4.3)

- The security testing and maintenance program was well implemented. The licensee's implementation of a hand geometry access control system was considered good (Section 4.3.2).

SAFETY ASSESSMENT AND QUALITY VERIFICATION

- Corrective actions for the damaged fuel grids were thorough (Section 1.4.1).

- The licensee's control, identification, and removal of foreign material in the areas around the fuel handling operations was excellent, and much improved over previous inspection findings (Section 1.4.2).

- The chemistry self assessments and quality assurance audits were sufficient in depth and identified concerns with procedural guidance, data review, and instruments. Corrective actions to address the observations were developed and implemented (Section 4.1.7).

Summary of Open Items
Violations: identified in Sections 1.3.1, 4.1.5 and 4.1.6.
Unresolved Items: non identified
Inspector Follow-up Items: identified in Sections 4.2.5 and 6.0.
Non-cited Violations: identified in Section 1.2 and 1.4.3.

INSPECTION DETAILS

1.0 OPERATIONS

NRC Inspection Procedure 71707 was used in ongoing inspection of plant operations.

1.1 Reactor Trip Due To A Controller Failure - Unit 1

On March 17, 1996, Unit 1 automatically tripped on low feed flow coincident with low steam generator level. All safety systems responded as designed. The cause was the failure of the differential pressure (d/p) controller for the main feed pumps.

The licensee initiated an investigation to determine the cause of the d/p controller failure and recent problems with other controllers. Other problems observed, which have not impacted the actual function of controllers, were intermittent loss of face plate display and loss of the audible beep associated with manual input. Preliminarily, the licensee believed that the root cause of some of the problems was electrostatic discharge. As an immediate action, the licensed operators were instructed to ground themselves prior to operating the controllers. The licensee was also evaluating long-term actions to eliminate the problem.

The 10 CFR 50.72 report stated the control room operators manually started the motor driven auxiliary feedwater pumps and that a "secondary safety" lifted (implying a steam generator code safety). The NRC identified that the trip report filled out by the balance of plant operator indicated that the pumps automatically actuated. Also, the NRC determined that the valve which actuated was a feedwater/heater system relief valve, not a steam generator code safety. The licensee investigated the discrepancy and concluded that the motor driven auxiliary feed pumps automatically actuated, and that the shift technical advisor misunderstood the operators' communication. The inspectors will further review this event during the review of the associated licensee event report (LER).

1.2 Procedural Adherence Issue - Unit 2

On March 5, 1996, the inspectors witnessed the non-routine evolution of removing the Unit 2 normal chemical and volume control system (CVCS) letdown flow path from service to support repair of 2-QRV-500, the deborating demineralizer divert valve. The inspectors determined that the operators did not follow procedure, 02-OHP 4021.003.001, "Removing Letdown, Charging and Seal Water From Service," when removing the normal letdown from service.

Procedure, 02-OHP 4021.003.001, paragraph 2.2.1, required closing the normal letdown isolation valves, the orifice isolation valves, and the letdown containment isolation valves (2-QCR-300 and 2-QCR-301). After closing these valves, the operators quickly reopened 2-QRC-300 and 2-QRC-301 to prevent the

lifting of a safety relief valve due to known leakby of the normal letdown isolation valves and the orifice isolation valves. The safety relief valve was installed on a portion of the piping that was isolated when letdown containment isolation valves were closed.

During discussions with the inspectors, the operators stated that since the procedure was not identified as an "in-hand" procedure, verbatim compliance was not required. The inspectors determined the licensee's administrative requirements for procedural adherence required that procedures not designated as "in hand" must also be followed. Since the leakby of the letdown and orifice isolation valves was a known problem and was anticipated by the operators, the procedure should have been changed prior to being performed.

Operations management initially did not consider this to be a procedural compliance issue because operators needed to have the flexibility to deviate from procedures for the purpose of placing the plant in a safer configuration. Since the leakby of the isolation valves was known by the operators, the inspectors did not consider this a valid reason to deviate from the procedure. Upon additional review, the licensee initiated a condition report to investigate the issue of procedure adherence and to document that a maintenance action request had not been initiated for the leaking orifice isolation valves. The inspectors also identified that action requests were initiated in May 1995 for the leaking letdown isolation valves, but the job orders (which maintenance workers utilize to perform work on equipment) had not yet been written due to the relatively low priority.

The failure to adhere to plant procedures as required by 10 CFR 50, Appendix B, Criterion V, constituted a violation of minor significance and is being treated as a Non-cited Violation, consistent with Section IV of the NRC Enforcement Policy. (50-316/96004-03)

The operators' desire to quickly reopen the letdown containment isolation valves to prevent lifting of a safety relief valve, due to known leakby of upstream valves was a known operator workaround that was not recognized as an operator workaround by the licensee.

1.3 Manual Reactor Trip From 20 Percent - Unit 2

March 23, 1996, while shutting down the plant for a refueling outage, the licensee manually tripped the reactor from 20 percent power. The licensee originally planned the manual trip in anticipation that this would be required in a soon to be issued NRC generic communication. However, when issued, NRC Bulletin 96-01, "Rod Insertion Problems," dated March 8, 1996, did not require a manual trip, but rather rod drop testing following a reactor shutdown. The licensee, however, decided to still manually trip the reactor from 20 percent power to collect true as-found rod drop data. The licensee also intended to use the manual reactor trip to meet the 18 month technical specification (TS) surveillance requirement (4.8.1.1.1) to verify operability of the auto-transfer of power from the normal auxiliary source to the preferred reserve source.

1.3.1 Procedure Revision Concerns

Prior to the trip, the inspectors reviewed the procedural revisions issued for performing this non-routine reactor shutdown for compliance with regulatory requirements. The following procedure revisions were reviewed:

- Change Sheet 3 to procedure 02-OHP 4021.001.003, "Power Reduction," revised the method of a planned reactor shutdown from an orderly reactor shutdown from power to a manually reactor trip from a power level that would result in the automatic starting of engineered safety feature equipment (ESF).

- Change Sheet 1 to surveillance procedure 02-OHP4030.STP.026, "Auxiliary Power Transfer Test Surveillance Procedure," revised when to perform the TS surveillance. Instead of performing the surveillance when the reactor was shutdown (Mode 5 or 6), the revision allowed the surveillance to be performed at power (Mode 1) using an actual ESF actuation (reactor trip).

TS 6.5.3.1.a requires that procedures which affect plant nuclear safety, and changes thereto, shall be prepared, reviewed, and approved. TS 6.5.3.1.e also requires that a procedural change be reviewed to determine if an unreviewed safety question exist. To facilitate implementing changes to procedures that do not change the intent of the approved procedure, TS 6.5.3.1.a describes the use of a temporary change process. These temporary changes deviate from the normal review and approval process by allowing these changes to be approved by two members of the plant staff, with at least one individual holding a senior reactor operator license and allows the safety review, to determine if an unreviewed safety question exist, to be conducted until 14 days after implementation of the change. The inspectors considered the above changes to procedures 02-OHP 4021.001.003 and 02-OHP4030.STP.026 as changes to the intent of the procedure and the temporary change process should not have been used.

The NRC discussed these concerns with licensee management on March 22, 1996. In response, the licensee revised the procedure 02-OHP 4021.001.00 using the normal procedural process, including the appropriate safety reviews, prior to tripping the unit on the following day. The licensee canceled the performance of surveillance 02-OHP4030.STP.026 due to the time constraint involved with the reviews for the proposed procedural change.

The use of the temporary change process to issue Change Sheet 3 to procedure 02-OHP 4021.001.003, "Power Reduction" and Change Sheet 1 to surveillance procedure 02-OHP4030.STP.026, "Auxiliary Power Transfer Test Surveillance Procedure" is a violation of TS 6.5.3.1.a and e (50-316/96004-01(DRP)).

1.3.2 Concern with the Process for Written Guidance to Operators

Plant Managers Instruction (PMI) 4090, "Criteria For Conducting Infrequently Performed Tests Evolutions," defines the controls to allow the use of written guidance to the operators which is outside of an approved plant procedure. PMI 4090 did not ensure that the additional guidance was evaluated for an unreviewed safety question. During the planning for the reactor trip from 20 percent power, the licensee used the PMI-4090 process to identify the option of a manual start of the motor-driven auxiliary feedwater pumps prior to the trip. PMI-4090 required a screening in order to provide additional written information to operators during certain evolutions. The inspectors were concerned that PMI-4090 did not require that a safety evaluation be performed to ensure that additional guidance to operators during infrequent tests evolutions did not constitute an unreviewed safety question.

1.4 PREPARATION FOR REFUELING - Unit 2

NRC Inspection Procedure 60705 was used to perform an inspection of the licensee's preparation for the planned Unit 2 refueling outage. This inspection primarily focused on the controls and implementation of core unloading activities.

1.4.1 Damage to Fuel Grid Straps - Unit 2

On April 3, 1996, while performing 100 percent in-mast sipping and visual examinations during the removal of the fuel, refueling personnel identified that three grid straps on the fuel assembly in core location P-11 were damaged. Two of three non-structural grid straps had one entire face removed and one of the seven structural grid straps had a narrow section (about the width of two fuel pins) removed. No significant damage to the fuel cladding occurred.

Prior to resuming fuel movement the licensee:

- Performed an assessment of this event.
- Performed an examination of the fuel and searching for the grid straps that were missing.
- Removed the grid strap piece that was sticking out of the fuel cell that was in the upender.

Based on inspection of the damaged fuel assembly and interviews of refueling personnel, the licensee determined that the grid damage to the fuel assembly in core location P-11 occurred during the removal of the fuel assembly at core location R-11. Core location R-11 was in the first row of assemblies removed, and therefore was restricted on three sides during removal. Two sides were adjacent to the core baffle, and one side was adjacent to the assembly in location P-11. To ensure that stress was reduced on the remaining assemblies to be removed, the licensee revised the unloading pattern. The new unloading pattern would be incorporated into future outages. As Unit 2 fuel was thinner than Unit 1 fuel, the problems with Unit 2 fuel bowing was more acute. The new unloading pattern was only applicable to Unit 2.

The licensee did not plan on reusing the once burned assembly that was the most damaged. The other assembly received minor damaged, but had already been used for three cycles and was not scheduled to be re-used. The licensee accounted for all pieces of the grid strap prior to initiating a re-load of the reactor vessel.

The NRC observations of fuel handling activities both before and after identification of the damaged assembly did not identify any significant problems. The licensee's corrective actions for the damaged grid straps was considered to be excellent.

1.4.2 Foreign Material Exclusion (FME) During Fuel Handling Operations

The licensee's control, identification, and removal of foreign material in the areas around the fuel handling operations was excellent, and much improved over previous inspection findings (IR 315/316-95010(DRP).

During a previous inspection (IR 315/316-95010(DRP), the inspectors had identified numerous examples of poor FME control around the fuel handling areas (e.g. spent fuel pool, reactor vessel, refueling cavity, etc). Based on these examples the licensee initiated improvements but, had not completed all the corrective actions. During this inspection period, the inspectors observed excellent FME control in the containment. Tight control was being maintained over the introduction of materials within the FME control zones and regular inspections and cleanups were being performed.

In addition to the FME controls around fuel handling areas, general containment cleanliness and housekeeping were also excellent. Licensee management made regular tours of containment and the fuel handling areas and prompt action was taken to correct any identified discrepancies. Marked improvement has been noted plant wide in FME controls.

1.4.3 Spent Fuel Pool Radiation Monitors

During a tour of the spent fuel pool (SFP) area and the containment during fuel handling operations the NRC determined the licensee had portable radiation monitors inside containment but did not have an operable portable monitor in the SFP area. The licensee normally had a portable radiation monitor in the SFP area, but due to maintenance the monitor was removed to replace the one inside containment.

UFSAR section 14.2.1.1 states, in part, during fuel handling operations: "In addition to the area radiation monitor located on the bridge over the spent fuel pit, portable radiation monitors capable of emitting audible alarms are located in the area during fuel handling operations." UFSAR section 14.2.1.2 states, in part: "In addition to the area radiation monitors located in the upper and lower containment volumes, portable monitors capable of sounding audible alarms are located in the fuel handling area."

The licensee did not have any procedural requirements to place portable radiation monitors inside of containment and around the SFP during fuel handling operations. This was apparently due to a lack of knowledge of the UFSAR commitment. Due to good radiological practices the licensee made it a practice of having portable radiation monitors inside containment but it was not proceduralized or occurring in reference to this commitment.

An additional contributor to the licensee's failure to identify this commitment was the failure to have the commitment in other UFSAR sections. For example the commitment was not contained in section 9.4, spent fuel pool, section 9.7 refueling, nor chapter 11 radiation monitoring. The licensee committed to revise the procedures to include the requirement to have portable radiation monitors in place prior to fuel movement.

The licensee failed to implement a commitment in the UFSAR. However, since other monitors were in the area and operable this failure constitutes a violation of minor significance and is being treated as a Non-Cited violation, consistent with Section IV of the NRC Enforcement Policy 50-316/96004-05.

Following NRC inspector questioning, the licensee began an assessment of the UFSAR requirements and the area radiation monitors. The licensee believed that the existing radiation monitor on the North wall of the SFP combined with the portable monitor located on the SFP bridge were adequate to meet the UFSAR commitment. However, the licensee performed a safety evaluation and UFSAR change request to use only the portable monitor on the bridge during refueling operations. This was completed prior to beginning core re-loading.

1.4.4 <u>Dual Train Outage</u>

During a routine review of control room paperwork, the NRC determined the licensee was planning on performing a dual train essential service water (ESW) and component cooling water (CCW) water outage during the Unit 2 refueling outage. Due to TS considerations the licensee's only work window would occur while the core was entirely off-loaded to the SFP. However, since one train of SFP cooling depended upon Unit 2 for power and cooling water, this would result in only one train of cooling being available to cool the SFP.

On January 3, 1996, the licensee had determined that the practice of having dual train ESW and CCW outages during a full core off-load exceeded the licensing basis and that the UFSAR contained errors which needed to be corrected. Condition report 96-0002 was written as required by procedure and immediate follow-up begun.

The licensee determined that as the design basis would not be exceeded, the dual train ESW/CCW outage planned for the Unit 2 refueling outage could be performed provided it was properly approved through the 10 CFR 50.59 process. A safety review, engineering assessment, and calculation were performed to verify no unreviewed safety question existed during the planned dual train outage.

Subsequently, due to a change in the scope of the ESW outage, the dual train ESW outage did not occur. The licensee also was able to isolate the CCW system for maintenance work in a manner which resulted in the need to perform a dual train CCW outage to be eliminated. Unfortunately due to a communications error there was still about 24 hours in which neither train of CCW was available to cool Unit 2's SFP cooling train. A separate CR was written to address the communications failure.

The licensee planned to update the UFSAR during the next annual update (June, 1996) to resolve the discrepancies identified in January 1996.

1.5 Closure of LERs - Both Units

(Closed) LER 50-315/95003: - Reactor trip due to turbine trip on loss of vacuum. This event was discussed in Inspection Report 50-315;316/95009 and a violation was issued (95009-01). No new issues were revealed by the LER.

(Closed) LERs 50-315/95004, 50-315/95005, and 50-316/94009: - Loss of 4-loop injection, unexpected auxiliary feedwater pump start, and engineered safety feature ventilation inoperability during surveillance. These events were reported based on discussion in Inspection Report 50-315;316/95009 and the issuance of a violation (95009-02). No new issues were revealed by the LERs.

(Closed) LER 50-315/95011: - West centrifugal charging pump inoperable for six months due to personnel error during relay calibration. This event was discussed in Inspection Report 50-315/95014 and escalated enforcement action taken (95014-01a). No new issues were revealed by the LER.

(Closed) LER 50-315/96001: New fuel vault criticality monitor. This event was discussed in Inspection Report 50-315;316/96002 and a violation was issued (96002-01). No new issues were revealed by the LER.

(Closed) LER 50-316/94008, 95004: - Reactor trip caused by turbine trip on hi moisture separator reheater level. These events were discussed in Inspection Report 50-315;316/95010. No new issues were revealed by the LER.

(Closed) LER 50-316/95005: - Reactor trip from trip of both control rod drive motor generator sets due to mis-adjusted voltage regulators. This event was discussed in Inspection Report 50-315;316/95010 and a non-cited violation was issued. No new issues were revealed by the LER.

(Closed) LER 50-316/95006: - Reactor trip on manual actuation of trip breaker control switch. This event was discussed in Inspection Report 50-315;316/95010 and a non-cited violation was issued. No new issues were revealed by the LER.

2.0 MAINTENANCE AND SURVEILLANCE

NRC Inspection Procedures 62703, 61726, and 92902 were used to perform an inspection of maintenance and testing activities.

2.1 Maintenance and Surveillance Testing Activities

The NRC observed routine preventive and corrective maintenance and surveillance activities to ascertain that these were conducted in accordance with approved procedures, regulatory guides, industry codes or standards, and in conformance with Technical Specifications (TS). The specific maintenance activities observed/reviewed are listed below:

♦	002619501	Repack RHR valve 2-RH-121W
♦	004073607	Lift and inspect Unit 2 upper internals
♦	001358105	Perform test on Unit 2 AB Battery
♦	004142907	Repair ice condenser bed
♦	003969203	Disassemble and repair pressurizer power operated relief valve 2-NRV-163

The specific surveillance activities observed/reviewed are listed below:

♦	02-EHP.4030.STP.211	Ice Condenser Surveillance
♦	1-OHP.4030.STP.027AB	Diesel Generator Slow Start
♦	02-OHP4030.STP.026	Auxiliary Power Transfer Test Surveillance Procedure
♦	02-OHP 4021.001.003	Power Reduction
♦	02-EHP.4030.STP.211	Ice Condenser Surveillance
♦	1-OHP.4030.STP.027AB	Diesel Generator Slow Start

2.2 Hydraulic Fluid Spill Inside Containment While On Line - Unit 2

On March 8, 1996, during an initial check out of the new containment jib crane, the crane was inadvertently rotated into an obstruction and caused a suction hose to the hydraulic pump to fail. Approximately 10 gallons of hydraulic fluid were spilled in containment while Unit 2 was operating. The spilled fluid was immediately cleaned up and an operability assessment was performed and determined that the operability of the ECCS recirculation system was not compromised. The licensee repaired the failed hydraulic hose, corrected the interference and resumed the check out of the jib crane.

On March 21, 1996, another spill occurred when the casing of the hydraulic pump cracked and about 8 gallons of fluid leaked into containment. The spilled fluid was cleaned up and the licensee had the same operability conclusions. The cause of the cracked casing was stresses introduced during the initial failure of the hose. The pump was replaced and the operability checks of the jib crane continued. While neither spill caused equipment to become inoperable, there were missed opportunities to improve performance in the installation of equipment while the unit was at power. The missed opportunities consisted of:

- Workers paying more attention to possible interferences during initial rotational checks of new equipment.
- The need to perform thorough checkouts of equipment following events where equipment is inadvertently damaged.

While the licensee's immediate actions of cleaning the spilled fluid were sufficient for the short term, the long term assessment failed to address the RCS chemistry effects. The initial cleanup consisted only of wiping the oil up with rags and no chemical cleaning was performed. Subsequently, while flooding the reactor cavity for refueling activities personnel reported a small oil sheen on the water. On April 16, 1996, with the unit de-fueled licensee personnel initiated a CR to document that the initial evaluation did not consider the effect of the oil mixing with the reactor cavity water and thus mixing with the nuclear fuel. The licensee made the evaluation a restraint for entry into Mode 5.

3.0 ENGINEERING

NRC Inspection Procedures 37550 and 37551 were used to perform an onsite inspection of the engineering functions.

3.1 Tracking of Ice Condenser Bypass Paths- Both Units

The inspectors had previously identified small instrumentation openings in Unit 1, between the upper and lower containment. The licensee stated since the openings were small and few in number, the design basis for ice condenser bypass was still met. During a recent tour of upper and lower containment, the inspectors had more questions regarding ice condenser bypass for some penetrations between upper and lower containment. The inspectors were informed by the system engineer that the ice condenser bypass design basis was a 50 ft^2. The inspectors determined that the design basis was only 5 ft^2. Based on the present bypass paths identified between upper and lower containment, approximately 44 percent of the allowable 5 ft2 ice condenser bypass was being used. The inspector were concerned that there was no tracking mechanism to ensure that the design basis for ice condenser bypass was met and that the system engineer did not know the allowable design basis for ice condenser bypass.

3.2 Secondary Side Transients - Unit 1

The air operated condensate booster pump (CBP) minimum control flow valve (emergency leak off or ELO valve) was designed to automatically open on low flow to protect the pump and to close automatically on higher flow. The discharge line of the CBPs was 20" in diameter with the ELO line being a 10" line. When the ELO valve opens, the diverted flow goes to the main condenser. The use of a 10" ELO line with a 20" pump discharge line results in large system pressure and flow perturbations when the ELO valves open or close. In an effort to reduce the perturbations, the operators modified the procedure to place the ELO valves in the open position, the designed position during a reactor startup, and then removing control power so the ELO valve remains open during power operations. This reduced the number of unexpected opening and closing of the ELO valve and system perturbations during plant operations.

On March 19, 1996, with Unit 1 at 30 percent power in preparation to close the ELO valve, the breaker for the control power was closed to the south CBP ELO valve in accordance with the startup procedure. However, when power was restored there was dual position indication for the ELO valve. Shortly afterwards excessive vibration was felt in the control room and various condensate heater, and condenser level alarms flashed in and out due to high and low indicated level. Control power was immediately removed from the valve. Local inspection revealed that the air supply line to the valve had partially broken off causing the ELO valve to rapidly oscillate and subsequently resulted in the air supply completely failing. Apparently, the air line had been loose and when power was restored to the valve the slight opening motion caused the line to fail. The piping around the south CBP was inspected for damage and a condition report was initiated.

One week later on March 27, 1996, with Unit 1 at full power, another CBP ELO valve transient occurred. A fitting on the air supply to the middle CBP ELO valve developed a large leak resulting in the valve going from the closed position to 50 percent open. The manual isolation valve was shut, air was isolated to the ELO valve and the valve was failed closed. When the ELO valve went 50 percent open some flow from the condensate system was diverted to the condenser and resulted in:

- An automatic start of the South CBP
- An automatic start of the East Turbine Auxiliary Cooling Water Pump
- A drop in the main feed pump differential pressure low
- High and low level alarms in the three hotwells

The operator workaround concerning the ELO was not recognized by the licensee as an operator workaround. This was similar to the licensee's failure to recognize the operator workaround discussed in paragraph 1.2 above.

4.0 PLANT SUPPORT

NRC Inspection Procedures 82701, TI 2515/131, 83750, 84750, 82701 were used to perform an inspection of Plant Support activities. Announced inspections of the Emergency Preparedness, Radiological Protection, Chemistry and Security were performed by region based specialists.

4.1 Radiological Protection and Chemistry (RP&C) Controls

4.1.1 Refueling Outage Radiological Controls (Unit 2) and As Low As Reasonably Achievable (ALARA) Program (IP83750)

The inspectors reviewed work activities and planning to ascertain the effectiveness of the ALARA program for this outage. Included in this assessment was a review of selected work packages, ALARA reviews, pre-job briefings, planning and scheduling, and the following jobs in progress:

- refueling activities
- scaffolding installation
- shielding installation

The inspectors also conducted tours of the containment, auxiliary and turbine buildings and had discussions with workers to determine their understanding of job requirements and dose rates.

The Unit 2 outage dose goal was set at about 140 person-rem (1.4 sievert (Sv)). Through day 29 of the outage, the station dose was approximately 135 person-rem (1.35 Sv) which was about 30 rem (0.30 Sv) above the projected dose

for that period. Contributing to the higher dose was about 10 person-rem (0.10 Sv) expended on additional work scope (work not originally scheduled). An additional 10 person-rem (0.10 Sv) was due to work performed on valves and components with dose rates that were higher than those found during the previous Unit 2 outage, and which were used to make the initial dose projections. The licensee was evaluating the cause of the unexpected higher dose rates on these components. Most of the remaining dose was attributable to problems with planning and/or preparation for work, such as the reactor vessel internals lift.

The early boration initiative removed about 600 curies of cobalt-58 from the system and appeared effective in reducing containment area dose rates. General area dose rates were only slightly higher than those found during the previous Unit 2 outage. ALARA initiatives included continued improvement in scaffolding planning and scheduling (a factor of two dose reduction over three years), mock up training, improved tool controls, and considerable use of shielding.

The projected non-outage dose for 1996 (32 rem (0.32 Sv) was twice that received in 1995 due in part to scheduled on-line maintenance and modifications.

Although some minor problems were noted with work planning, radiological controls in the Unit 2 refueling outage were generally well implemented and there appeared to be good radiological work practices. Source term reduction and shielding efforts continued to be successful in reducing radiation exposure, and ALARA planning for the large exposure jobs was generally thorough. The dose expended to date, although higher than estimated, was reasonable considering the added work scope and higher than expected dose rates.

4.1.2 <u>Tour of Unit 2 Containment and Station Auxiliary Building</u>

The inspectors toured various work areas in the plant and observed work in progress. Interviews of workers and radiation protection technicians were conducted to determine if the workers were knowledgeable of the radiological conditions in the work area.

During a tour of the Unit 2 upper containment the inspectors and the station Radiation Protection Manager (RPM) identified one person lying down in a low dose area, other workers leaning on a hand rail in an area posted " Do Not Linger," and several other workers who appeared to be loitering. Dose rates in these areas ranged from about 1 to 3 mrem/hr and the RPM instructed those workers who were not currently performing a task to move to a lower dose area.

During a tour of the refuel floor, the inspectors noted that a portable ventilation hose taking suction from the hot maintenance shop was routed with about a 180 degree bend, thus creating the potential for reducing the design air flow. This matter was discussed with the RPM who had the situation

corrected. A worker was also identified sitting on a potentially contaminated lathe in the hot shop. After discussing this with the floor RP technician, the worker was requested to move.

The tours of the radiologically controlled areas generally demonstrated good radiological housekeeping and worker RP practices, but raised a question concerning about how well persons who appeared to be loitering in the upper containment were challenged by RP and first line supervisors. The inspectors observations were discussed with the RPM and plant manager who indicated these observations would be addressed.

4.1.3 Control and Review of Water Chemistry (IP 84750)

The inspectors reviewed the licensee's plant water chemistry over the last 12 months, including the sample collection and the evaluation/trending of chemical impurities in plant water systems.

Overall, primary and secondary water quality were well maintained. The licensee implemented aggressive goals (contained in chemistry procedures) for steam generator (SG) and condensate chemistry impurities. With the exception of condensate oxygen concentrations, secondary water chemistry was maintained within the licensee's goals. Oxygen inleakage resulted in several periods of operation at condensate oxygen concentrations of 5-7 ppb, which is above the licensee's goal of 2-5 ppb. The licensee was aware of this problem and indicated corrective actions were being taken to address this problem.

The inspectors observed that the concentrations of chloride and sulfate increased at times when the opposite unit was undergoing startup and shutdown. During startup evolutions, the chemistry staff indicated that the reverse osmosis (RO) makeup water purification system had a output capacity that could not adequately meet demands for both units. The licensee plans to upgrade the RO system to increase capacity in 1996.

Although chemistry technician (CT) knowledge was found to be very good, the inspectors noted some weaknesses in the CTs knowledge of chemistry action levels and in the ability to identify data exceeding those limits. Prior to a chemistry supervisory review, the inspectors noted that a CT, preparing a chemistry data sheet for April 1, 1996, failed to properly indicate an out of specification Unit 1 Steam Generator (SG) 11 chloride level. The inspectors discussed this with a different CT who was not familiar with the meaning of the licensee's different limits (i.e. goals, limit, and action levels). Subsequently, the licensee corrected the data sheet and obtained an additional sample. The licensee indicated that this performance did not meet management expectations and that these weaknesses would be addressed.

Contaminants in plant water systems were generally controlled at or below the licensee's aggressive goals. The periodically elevated chemistry contaminants were attributable to oxygen inleakage into the condensate system and the limited capacity of the RO system. Some weaknesses in CT performance were observed, which was inconsistent with management's expectations.

4.1.4 Implementation of the Radiological Environmental Monitoring Program (REMP) (IP 84750)

On April 3, an inspector accompanied a licensee representative during REMP air and drinking water sample collection. The inspectors also interviewed the REMP staff regarding other sampling activities and reviewed the REMP data for 1994 and 1995.

The REMP sample collection and analyses were conducted in accordance with the ODCM. All omissions were noted in the reports. The inspector reviewed recent data for groundwater tritium originating from the Absorption Pond, and no adverse trends were evident. Other than groundwater tritium, the REMP data for 1994 and 1995 indicated no radiological impact to the environment from plant operations.

All air samplers were operational and within calibration. The observed sampling activities were good. However, the inspector noted that the collector had some difficulty removing the air filter from the sample head, and also that the air sample collection procedure did not provide any guidance for the removal of the air particulate filter. Improper air filter removal can have an effect on sample integrity. The licensee indicated that both the procedure and practice would be reviewed to ensure that air filter removal was proper and consistent among the collection staff.

Overall, the REMP was effectively implemented.

4.1.5 Post Accident Sampling System (PASS)

During this inspection, inspectors reviewed weaknesses in PASS activities that were identified during the integrated performance assessment (IPAP) documented in NRC Inspection Report Nos. 50-315/316-96003, Section 5.2. This review, using procedure 12 THP 6020 PAS.016, "Post Accident Sampling Quality Assurance," revision 2, included assessing the operability and quality control (QC) program for PASS. The inspectors also observed a chemistry technician (CT) obtaining a PASS sample.

The inspectors had identified, during the IPAP, that the below listed comparisons between the PASS analyses and routine analyses did not satisfy the licensee's criteria and were not performed at the frequency required by procedure 12 THP 6020 PAS.016. Based on the inspectors findings during the IPAP, the licensee had issued condition reports (CRs) for these discrepancies.

- On August 22, 1995, monthly boron comparisons did not meet the licensee's acceptance criteria. Monthly pH, oxygen, and gas chromatograph (GC) samples were not completed in August 1995. On September 5, 1995, the system log book noted that samples were not obtained as the system was out of service, yet returned to service the same day.

- On September 28-29, 1995, monthly comparisons for the GC, pH, and nuclide activity did not meet the licensee's acceptance criteria. A monthly boron comparison was not completed in September 1995. The system log book indicated that resampling was not completed because of lack of time.

- On October 2, 1995, the monthly comparison for pH did not meet the licensee's acceptance criteria. Monthly comparisons for the GC, boron, and nuclide activity were not performed in October 1995.

- PASS boron samples for November and December 1995 monthly comparisons were discarded prior to analysis. No resampling was performed.

Technical Specification (TS) 6.8 requires a program for post accident sampling be implemented which includes procedures to ensure the capability to analyze reactor coolant samples. Procedure 12 THP 6020 PAS.016, which ensures proper PASS system and instrument functioning for analyzing reactor coolant samples, required monthly comparisons between routine grab samples and the PASS system for the PASS pH monitor, oxygen monitor, GC, and boron. The failure to perform monthly comparisons as described above is an example of a violation of TS 6.8 (Violation Nos. 50-315/316-96004-02a). The failure to take corrective actions for comparisons outside of the acceptance criteria, as required by procedure 12 THP 6020 PAS.016, is another example of a violation of TS 6.8 (Violation Nos. 50-315/316-96004-02b).

Once identified by the inspectors during the IPAP, the licensee performed some immediate corrective actions including the counseling of the chemistry supervisor responsible for the program. The acting chemistry superintendent informed the inspectors that the supervisor was unaware of the procedural requirements and relied on the experience of the CT performing the analyses. The licensee had also performed several isotopic comparisons to calculate the system dilution factor, which had not been performed since October 1, 1993. The results of those analyses indicated a dilution of about 800 versus the 1000 the licensee had been using. Additionally, the inspector reviewed the licensee's February 1996 comparisons, which were complete with followup action taken for analyses not meeting acceptance criteria.

On April 3 and 4, the inspectors observed a CT calibrating the online pH meter and collecting of a diluted liquid sample, respectively. A tritium analysis of the diluted liquid sample was in good agreement with a routine grab sample. Although the CT had the applicable procedures in hand, the CT encountered a number of problems. During the liquid sampling, an inspector identified to him that he had inadvertently started the sample drain pump instead of actuating a system valve. Additionally, he performed some steps out of sequence and had to return to various parts of the procedure to complete the process.

As identified in the IPAP, weaknesses were observed in licensee oversight of the PASS program that resulted in two examples of a violation concerning adherence to procedure 12 THP 6020 PAS.016. Additionally, the inspectors identified a CT that had difficulty operating the PASS in accordance with chemistry procedures.

4.1.6 Chemistry Laboratory Quality Control (QC)

The inspectors observed laboratory activities, reviewed pertinent QC records, and interviewed laboratory and Quality Assurance (QA) personnel regarding laboratory QC. The analytical areas reviewed included radiochemistry, non-radiochemistry, and on-line instrumentation.

The implementation of the radiochemistry QC was good. The QC records for Lower Limit of Detection (LLD) indicated that the gamma isotopic analysis system was capable of achieving satisfactory LLDs. In addition, the laboratory demonstrated excellent radioanalytical capabilities as evidenced by 100 percent agreement with the vendor cross-check program in 1995. However, the 1996 control charts for all the counting instruments indicated the existence of minor trends and biases, as defined in Procedure 12 THP 6020 ADM.001, "Quality Control," Rev. 0.

The implementation of the non-radiochemistry QC was adequate. The inspectors noted that the laboratory was well equipped and the licensee had established a computer-based system (CDMS) to track the QC performance of the instruments. However, the lab staff recording of QC data into the CDMS was inconsistent. Another QC data inconsistency pertained to the use of performance check data from analyses that were considered non-regulatory. In these instances, the performance check data was used only if the data point indicated a problem with the instrument, but not if the data point was acceptable. Therefore, the inclusion of these data points in the QC program was not uniform.

The inspectors reviewed QC data for the past six months for chloride and sulphate analysis on the ion chromatographs and noted a number of biases and trends which were not evaluated and recorded as required by Sections 6.2.4 through 6.2.7 of 12 THM 6020 ADM.001, "Quality Control, Rev. 0.

- Chloride performance checks on instrument I04 indicated two biases and one trend from October 1995 to April 1996.

- Chloride performance checks on instrument I06 indicated two biases and one trend from October 1995 to April 1996.

- Sulphate performance checks on instruments I04 and I06 indicated one and two biases, respectively, from October 1995 to April 1996.

The lack of procedural adherence in the evaluation and documentation of this QC information is an example of a violation of TS 6.8, which requires, in part, that procedures be implemented as recommended in Regulatory Guide 1.33, Appendix A (Violation Nos. 50-315/316-96004-02c).

The QC for online instrumentation was good. The licensee conducted performance checks in accordance with QC procedures. However, there was an inconsistency in the procedural definition of acceptance criteria for the QC data. Attachment 3 of Procedure 12 THP 6020 ADM.003, "Online Instrument Quality Control," Rev 1, indicates that the acceptance criteria for hydrazine is +/- 15 percent for "As Found" and +/- 10 percent for "As Left." The inspectors noted that hydrazine QC data on January 26, 1996 exceeded these criteria, and there was no indication of corrective action, as stated in Section 6.3.4. The licensee indicated that the procedure required corrective action only for regulatory parameters and that this procedure would be reviewed to clarify the use of acceptance criteria for non-regulatory parameter analyses.

Laboratory QC was good, with the exception of procedural adherence and supervisory review of QC data. An example of a procedural adherence violation was identified regarding the review of control charts. In addition, inconsistencies were identified concerning the application of the QC program, which may decrease the overall effectiveness of the program.

4.1.7 Review of Chemistry Self Assessments and Quality Assurance Audits

During the inspection, the inspectors reviewed chemistry Quality Assurance (QA) activities. The chemistry staff, with assistance from a QA auditor, performed self-assessments of selected chemistry program elements during the past six months. For the elements reviewed, the self-assessments had sufficient depth and contained several good observations concerning procedural guidance problems, data review deficiencies, and instrument issues. Corrective actions to address the observations were developed and implemented. However, as discussed in the IPAP inspection, the self-assessments were not effective in ensuring the 1993 and 1994 self-identified problems with chemistry sampling and QC were resolved.

4.2 Operational Status of the Emergency Preparedness (EP) Program (IP 82701)

4.2.1 Actual Emergency Plan Activations

An Unusual Event was declared at 11:15 a.m. on May 5, 1995 when a review of past inservice inspection examinations determined that the ultrasonic examination procedure used to inspect Reactor Coolant System branch connection welds was inadequate to meet welding code requirements. As such, the requirements of Technical Specification (TS) 4.0.5 had not been met for emergency core cooling systems, and a reactor shutdown was required per TS 3.0.3. The Unusual Event was terminated at 1:10 p.m. the same date when an operability determination indicated the reactor shutdown was overly conservative and other means were available to resolve the nonconformance.

An Unusual Event was declared at 1:00 a.m. on August 20, 1995, due to an explosion in the phase 2 main transformer output bushing. The transformer was energized but not providing power when the explosion occurred. The Unusual Event was terminated at 1:50 a.m. on the same date.

An Unusual Event was declared and terminated at 11:55 a.m. on August 22, 1995, due to a fire on the auxiliary building roof. The fire, caused by roofing repairs, was extinguished within eight minutes. The Unusual Event was terminated at the same time as it was declared, as the fire was extinguished by that time.

Records reviewed indicated that classification and notifications had been made properly and in a timely manner. Documentation for the events were complete, and technically correct. A formalized procedure did not exist for standardized review, critique, and tracking of corrective actions related to actual emergency plan activations.

4.2.2 Emergency Plan and Implementing Procedures

The licensee had submitted a revision to the Emergency Action Level (EAL) scheme devised by the Nuclear Management and Resources Council (NUMARC). This submittal was under review by the NRC at the time of this inspection. When approved, procedure and training changes will be needed to implement the new EALs.

The inspector reviewed a representative sample of Emergency Plan Implementing Procedures. No problems were identified.

4.2.3 Emergency Response Facilities, Equipment, Instrumentation and Supplies

Tours were conducted through the Technical Support Center (TSC), Operations Support Area (OSA), and Emergency Operations Facility (EOF). Each facility was well maintained and in an excellent operational state of readiness. Current copies of the Emergency Plan, Emergency Plan Implementing Procedures and appropriate forms were present in each facility. The field monitoring team van was inspected, as well as field monitoring kits intended to be utilized for field teams. All inspected items were in good material condition.

A building has been purchased in the town of Buchanon, Michigan, to house the EOF and Joint Public Information Center (JPIC), as well as individuals from the Columbus, Ohio, corporate office. Inspection of the building indicated it has adequate room for both functions. Layout of both facilities was yet to be determined.

Documents reviewed indicated that emergency equipment inventories and maintenance were very good, with timely corrective actions taken where deficiencies were identified. No problems or concerns were identified.

4.2.4 Organization and Management Control

The overall organization and management control of the EP function was largely unchanged from the last inspection, except that the EP staff now reported to the Site Vice President.

The possibility was discussed that one of the corporate staff would join the plant EP staff. This would consolidate EP functions in one location and aid with the current EP workload (relocation of the EOF, NUMARC EAL procedure revisions and training, routine program maintenance, drills, exercises, Severe Accident Management implementation).

4.2.5 Training

Records indicated that drills and exercises were formally critiqued, training had been provided on formal critiques, and significant critique items were appropriately selected for corrective action.

Printouts from the training tracking systems were compared with "Emergency Call List," with no problems identified. The EP staff had proactively recognized that some personnel with emergency response positions would be leaving the organization, identified their positions on a timely basis, and were in the process of selecting and training replacements.

The results of interviews with two key emergency response persons were generally good. Very good knowledge of emergency responsibilities and activities were generally evident during these interviews.

The inspectors interviewed an individual assigned as Technical Support Center Director (TSCD) that had initial training and participated in three drills. During the training the TSCD had not been required to perform offsite communication related to classification changes and Protective Action Recommendations (PARs) during TSC drills. The inclusion of objectives in periodic TSC drills to develop and perform offsite communications relating to PARs will be tracked as an Inspection Followup Item 315/316/96003-04.

Review of EP training records and documentation revealed that excellent training appeared to be provided to emergency response personnel. A sample of lesson plans was reviewed. No concerns were identified.

4.2.6 Audits

The inspector reviewed Nuclear Safety and Design Review Committee Audit No. 220, "Emergency Plan," dated April 6, 1995. The audit resulted in four Condition Reports, ten recommendations and four Points of Information. The audit concluded that the "Cook Plant Emergency Plan is being effectively carried out," and noted many positive program qualities.

Also reviewed was Plant Performance Assurance Audit No. QA-96-02, "Emergency Planning and Preparedness (PMI-2080)," dated March 20, 1996 performed during January 15 - March 7,1996. This audit was performed by five individuals and concluded that adequate controls were established to effectively implement the program. Two recommendations and three points of information were associated with the audit. The audit was complete and well detailed.

The 1996 audit was weak in the area of assessment of the interface with offsite authorities, (the 1995 audit was very detailed in this area) but noted that a subsequent surveillance would be conducted in this area.

The 1995 and 1996 audits of the EP program satisfied the requirements of 10 CFR 50.54(t) with respect to scope. Records also indicated that the EP staff fulfilled the requirement to make relevant 1995 audit results available to State and county officials in 1995.

4.2.7 Communications (TI 2515/131)

The Emergency Plan, section 12.3.7 "Emergency Communications," section 12.3.7.2," Off-Site Communications," described the various communications systems available for offsite communications. These included:

1. microwave system
2. V.H.F. radio system
3. telephone lines

The following telephone systems were discussed with licensee personnel:

1. Fiber optic line to Benton Harbor via microwave link
2. Fiber optic line to Fort Wayne
3. Fiber optic line to the training center
4. Fiber optic line to Columbus
5. Fiber optic line to GTE

Fiber optic lines were described as buried in some areas, but came to the surface and shared a common manhole system. All lines came into a common room located on the second floor of the lakeside office building, an inside room without windows. A router was available which would switch calls to operable lines in case of individual line failures. Battery backups for fiber optic lines had an assumed capacity for 4-5 hour operation. Three chargers maintained the battery system.

A low-frequency radio transmitter with an 8-hour uninterruptable power system (UPS) (including diesel backup) was utilized by Security personnel. Equipment for this system was located at the 595 foot elevation, in the underground security equipment room. System antennas were on the turbine building roof and a UHF radio was used to communicate with the Berrien County Sheriff, utilizing the same UPS. Control point consoles for this system include the Central Alarm Station, Secondary Alarm Station, and Control Room.

An offsite repeater system was present at the microwave tower, equipped with propane powered generator backup power. Control points for this system were located at the OSA and EOF. The EOF microwave link could control the repeater and function like a mobile unit. Seven company cellular telephones were available, assigned to management and on-call personnel.

Discussion indicated that there was no formalized procedure for actions to take in the event of a major communications failure. However, a comprehensive package of information, "E-Plan Communications," had been developed to aid in evaluating/restoring communications in case of major damage to the microwave tower or PBX room. Line drawings of the various systems were included in the package. This documentation package, prepared due to findings in a previous drill or exercise, described which systems would remain after various failures (microwave tower or PBX switchroom).

Procedure PMP 2081 EPP.207, "Barring of PBX," provides for actions to modify the plant Private Automated Branch Exchange (PBX) to eliminate direct communications between selected plant and all offsite telephones. The TSC

Administrative Coordinator is responsible for implementing this procedure, which directs telecommunications personnel or the Security Director to bar the PBX. Barred telephones cannot initiate outgoing calls, limiting communications to those needed in an emergency.

The overall status of the emergency preparedness (EP) program was very good. Response facilities were in an excellent state of operational readiness. The 1995 and 1996 Audits of the EP program were very good, and satisfied the requirements of 10 CFR 50.54(t). The 1996 evaluation of the interface with offsite authorities was pending surveillance completion. A concern was identified relative to Technical Support Center drill objectives. Emergency communications capability was reviewed. No UFSAR deviations were identified.

4.3 Security

NRC Inspection Procedure 81700 was used to perform an inspection of plant support activities. The licensee's testing, maintenance, and compensatory measures programs were well conducted, ensuring the reliability of physical protected related equipment and security related devices.

4.3.1 General Overview

The licensee employed compensatory measures in accordance with approved security plan commitments when equipment failed or its performance was impaired. Those licensee personnel responsible for maintaining security systems demonstrated pride and ownership. Significant decreases in the number of security equipment and personnel error safeguards loggable events were noted during the first quarter of 1996. The licensee properly installed and effectively implemented a hand geometry protected area access control system. Improvement was noted in the efforts to reduce the number of vital area tailgating incidents. The licensee declared operable the physical installation of the vehicle barrier system upgrades required by 10 CFR 73.55 (C)(7) for protection against malevolent use of vehicles at nuclear power plants on February 23, 1996

4.3.2 Biometrics Hand Geometry System

On December 18, 1995, the licensee implemented a biometrics hand geometry access control system at the entrance to the protected area. By letter dated December 15, 1995, the NRC granted the licensee an exemption to 10 CFR 73.55 badging requirements relating to the issuance, storage and retrieval of picture badges for individuals who have been granted unescorted access to the protected area. Specifically, the exemption allowed individuals to keep their picture badge in their possession when departing the site. The NRC observed that the new system functioned well.

5.0 Follow-up on Previously Opened Items

A review of the following previously opened inspection items was performed using Inspection Procedure 92901.

(Open) Inspection Followup Item No. 315/94019-02: Training modules for key incident response personnel did not contain information relative to the NRC Incident Response Program nor that of the Department of Energy. A training session had been conducted on this information, but the training module had not had this material included. This item will remain open.

(Closed) Inspection Followup Item No. 50-315/94019-01: Procedure 12 THP 6010 RPP.009 (Rev.8),"Emergency Equipment Inventory" provided for monthly inventories but specific numbers of supplies or other equipment were not provided for inventory purposes. Minimum quantities of supplies or equipment had been added to the inventories. This item is closed.

(Open) Inspection Followup Item Nos. 50-315/95007-02; 50-316/95007-02: During the 1995 Exercise there was confusion over the initial protective action recommendation (PAR). Verbal communication erroneously referenced a PAR of sheltering. The EOF manager called the State and clarified the issue, but confusion over the PAR continued for some time. verbal communication of Protective Action Recommendations to the State of Michigan. This also occurred during a drill. A consultant was commissioned to review the PAR communication process and recommend corrective actions as necessary. This item will remain open.

(Closed) Inspection Followup Item Nos. 50-315/95007-01; 50-315/95007-01: During the 1995 Exercise, there was no organized or structured debriefing process for returning inplant response teams. A simple form (exhibit H to procedure PMP 2081 EPP.203) had been developed to guide the debriefing process. The form had been utilized in several drills with good results. This item is closed.

(Closed) VIO 50-315/316-95011-01(DRS): Review licensee corrective actions addressing an event in which an access control clerk incorrectly identified a contract employee as having been tested and reported as negative for chemical substances. The clerk failed to properly use information provided to prevent misidentification. As a result of this failure, the contract employee worked with unescorted access status in the plant protected/vital area from August 19 through August 22, 1995.

The NRC verified that the corrective actions listed in the licensee's dated November 15, 1995 to the apparent violation. These actions appear to be effective and here was no recurrence of these events. This item is closed.

(Open) IFI 50-315/316-95012-03(DRS): Review licensee actions addressing inspector concerns about an adverse trend in the number of tailgating incidents during the second and third quarters of 1995.

Heightened employee awareness of the functioning of the new security card reader system and continued senior management attention to this issue indicated improvement in this area. There were three tailgating incidents recorded during the first quarter of 1996. Two of the incidents were related to ignorance of the functioning of the system by employees with infrequent site access. The third was related to an employee who believed that he had received authorization into an area.

The licensee thought that similar incidents with the old card reader system occurred, but that the old system was incapable of identifying such occurrences.

6.0 Review of UFSAR Commitments

A recent discovery of a licensee operating a facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compared plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the NRC reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures, and/or parameters observed by the NRC.

- During a tour of the spent fuel pool (SFP) and containment areas, the NRC determined the licensee had portable radiation monitors inside containment but did not have an operable portable monitor in the SFP area. (Section 1.4.2) (50-315/96004-05)

- The licensee had determined that the practice of having dual train ESW and CCW outages during a full core off-load exceeded the licensing basis and that the UFSAR contained errors which needed to be corrected. (Section 1.4.4) (50-315/96004-06)

7.0 Meetings and Other Activities

a. Exit Meeting

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

At the conclusion of the inspection on April 16, 1996, the NRC met with licensee representatives (denoted by *) and summarized the scope and findings of the inspection activities. During this inspection de-briefings were held periodically with licensee management. Some of the persons listed below were present for only some of the de-briefings. The licensee did not identify any of the documents or processes reviewed by the NRC as proprietary.

*A. Blind, Site Vice President
*J. Sampson, Plant Manager
*K. Baker, Assistant Plant Manager
*D. Noble, Radiation Protection Superintendent
*T. Postlewait, Site Engineering Support Manager
*J. Wiebe, Superintendent, Plant Performance Assurance
*W. Hodge, Plant Protection Supervisor
*J. Allard, Maintenance Superintendent
*P. Schoepf, Plant Engineering Superintendent
*T. Beilman, Scheduling Superintendent
*M. Mierau, STA Supervisor

*D. Londot, ICS Supervisor
*M. Ackerman, Licensing Supervisor
*J. St. Amand, Plant Engineering Supervisor
*R. West, Licensing Coordinator
*R. Ptacek, Licensing Coordinator
*D. Hafer, NED Engineering Supervisor
*R. Krieger, Emergency Preparedness Coordinator
*E. Fitzpatrick, Senior Vice-President Nuclear