AUGMENTED INSPECTION TEAM REPORT

U.S. NUCLEAR REGULATORY COMMISSION

PERRY UNIT 1 CIRCULATING WATER PIPE BREAK

JANUARY 17, 1992

INSPECTION REPORT NO. 50-440/91026(DRS)

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-440/91026(DRS)

Docket No. 50-440 | License No. NPF-58

Licensee: Cleveland Electric Illuminating Company
Post Office Box 5000
Cleveland, OH 44101

Facility Name: Perry Nuclear Power Plant

Inspection At: Perry Site, Perry OH

Inspection Conducted: December 22 - 29, 1991

Inspectors: J. H. Neisler, DRS
R. B. Landsman, DRP
J. F. Schapker, DRS
J. E. Tatum, NRR
A. Vegel, Resident Inspector - Perry

Approved By: Rolf A. Westberg
Rolf A. Westberg,
Team Leader
1/17/92
Date:

Approved By: Ronald N. Gardner
Ronald N. Gardner, Chief
Plant Systems Section
1/17/92
Date:

Inspection Summary

Inspection on December 22-29, 1991 (Report No. 50-440/91026(DRS))

Areas Inspected: Special Augmented Inspection Team (AIT) inspection conducted in response to the circulating water pipe break event at Perry Nuclear Power Plant on December 22, 1991. The review included validation of the sequence of events, determination of the root cause for the pipe break and equipment failures during the event, review of the circulating water system's performance and maintenance history, evaluation of operator response to the event, evaluation of the effects of flooding, evaluation of the licensee's event classification and reporting, and evaluation of the licensee's corrective actions.

Results: No violations or deviations were identified in any of the areas inspected. No significant operational safety parameters were approached or exceeded. The AIT concluded that the root cause of the failure was inadequate design of a support adjacent to the auxiliary circulating water system pipe elbow that failed. The licensee did not implement recommendations in a 1982 consultant's report relative to the repair and modification of this pipe

Results Continued:

support. Instead, a temporary repair was made to address problems experienced during construction and was allowed to become a permanent modification without adequate design analysis. The specific failure mechanism involved a loosening of the pipe support anchor bolts which, in turn, permitted excessive movement of the fiberglass circulating water pipe elbow. Potential contributors to failure may also have been a manufacturing flaw which existed in the fiberglass elbow or an incorrectly installed fiberglass pipe splice. Catastrophic failure of the pipe prevented drawing definitive conclusions on this point.

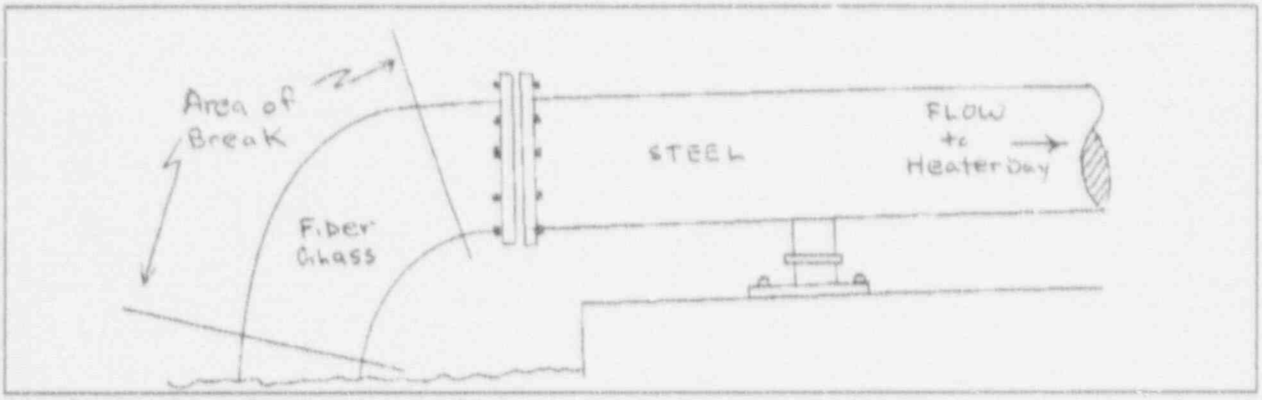
The team concluded that the operators safely responded to a challenging plant event and that their actions were indicative of a strong knowledge of plant systems and procedures.

Licensee recovery from this event was thorough. Corrective actions were generally good; however, modifications made to correct pipe support design deficiencies were not adequately evaluated. Inadequate consideration was given to the long-term affects of the dynamic forces on the fiberglass piping and pipe supports which had led to the recent failures. In response to NRC concerns, the licensee committed to perform a more rigorous piping analysis and special monitoring of the affected piping.

1.0 Introduction

1.1 Event Summary

On December 22, 1991, at 1:50 am, a 36 inch fiberglass pipe carrying circulating water from the cooling towers to the auxiliary condenser broke at the point where the pipe exits the ground, makes a 90° bend, and transitions from fiberglass to steel. It was located outside the plant in the North plant yard approximately 20 feet from the turbine building heater bay. Water from the pipe break entered the plant via electrical conduit which originated in manholes in the transformer yard and caused some minor flooding (up to 6 inches) of areas inside the plant. The leak was subsequently stopped when operators secured the pumps to the broken line. Reactor operators manually scrammed the reactor from 100 % power at 2:00 am. An Alert was declared under the plant's emergency plan at 2:59 am due to ground water in the heater bay being above the 590 foot level. The plant was placed in cold shutdown and the Alert was terminated on December 22, 1991, at 11:04 am.



Auxiliary Circulating Water Pipe

The resident inspectors responded to the event. A subsequent review by the residents and licensee personnel indicated that no safety related equipment was affected by the flooding. Some non-safety related equipment such as lighting and radiation monitoring was affected. No water was observed in rooms containing Emergency Core Cooling System (ECCS) Equipment. Some radioactive contamination of basement floor areas in the auxiliary and intermediate buildings resulted from floor drains backing-up.

1.2 AIT Formation

Region III staffed the Incident Response Center (IRC) and headquarters personnel monitored the event. Senior NRC managers determined that an Augmented Inspection Team (AIT) was warranted to gather information on the auxiliary circulating water pipe break and other equipment failures which occurred during the event. On Sunday, December 22, 1991, an AIT was formed consisting of the following personnel:

Team Leader: R. A. Westberg, Team Leader, Plant Systems Section, Division of Reactor Safety

Team Members: A. Vegel, NRC Resident Inspector, Perry Nuclear Power Plant
J. H. Neisler, Reactor Inspector - Electrical, Plant Systems Section
J. F. Schapker, Reactor Inspector - Mechanical, Materials and Processes Section
R. B. Landsman, Reactor Inspector, Division of Reactor Projects
J. E. Tatum, Senior Reactor Inspector, Office of Nuclear Reactor Regulation

The team leader and three of the team members arrived on site during the afternoon of December 22, 1991. The full team was on site the morning of December 23, 1991. In parallel with formation of the AIT, RIII issued a Confirmatory Action Letter (CAL) (attachment 1) on December 24, 1991, which confirmed certain actions in support of the team and established conditions required to be met prior to the restart of the plant.

1.3 AIT Charter

A charter was formulated for the AIT and transmitted from E. G. Greenman to R. A. Westberg on December 24, 1991, (attachment 2) with copies to appropriate EDO, NRR, AEOD, and RIII personnel.

The AIT was terminated on Sunday December 29, 1991.

2.0 Description of the Event

2.1 System Description

The purpose of the Circulating Water System (N71) is to remove waste heat from the Main and Auxiliary Condensers and to dissipate heat to the environment. The N71 system is a closed loop system consisting of one natural-draft cooling tower, the main and auxiliary condensers, three circulating water pumps, a mechanical cleaning system, a water box drain tank and pump, and various valves required to operate the system. Makeup water for wind losses, evaporation, and losses due to blowdown is obtained from the service water system (P41) at a rate of approximately 16,000 to 23,300 gallons per minute (GPM).

The flow path for the N71 system is from the cooling tower basin through a set of fixed screens to the suction of the circulating water pumps. The pumps discharge water through a 12-foot diameter pipe to the main condensers. The auxiliary condensers get their supply from a 36 inch pipe which taps off the main pipe. From the condensers, water flows out to the cooling tower where it cascades through a set of baffles, is cooled by the air flow, and returns to the cooling tower basin.

2.2 Sequence of Events

At 1:38 am on December 22, 1991, reactor power was increased from 99 % to 100 % upon completion of weekly surveillance No. SVI-N31-T1151. At 1:52 am, Annunciator No. 1H13-P870 was received for low circulating water suction chamber level. At 1:54 am, the Secondary Alarm Station (SAS) informed the control room that the motor and diesel fire pumps had auto started and that the start-up transformer deluge system had initiated. SAS also reported that a large vapor cloud had been spotted in the vicinity of the Unit 1 start-Up transformer. At 1:57 am, control room personnel observed that the cooling tower basin level was rapidly decreasing and that pump ampere and discharge pressure readings were oscillating considerably for all N71 pumps. A rapidly degrading vacuum in the "A" auxiliary condenser was also noted at this time.

At 2:00 am, the control room unit supervisor ordered a decrease in reactor power to 80 % via reduction in reactor recirculation system flow hoping that the "A" auxiliary condenser could be isolated; however, control room personnel soon noted that vacuum was also decreasing in the "B" auxiliary condenser. At this time, plant personnel began contacting the control room with reports of large amounts of water in the transformer yard and turbine building. After observing a continued rapid decrease in cooling tower basin level and severe oscillations in circulating pump amperes and discharge pressure, the unit supervisor declare entrance into IOI-8 (Shutdown by Manual Scram). Reactor vessel core flow was reduced to 52 Mlbm/hr and a manual scram was initiated at 2:05 am. Procedure No. PEI-B13 (RPV Control) was entered when water vessel level dropped to level 3, or 178 inches above the active fuel. This level causes a reactor scram signal, isolation of Residual Heat Removal (RHR) shutdown cooling, and run-back of the reactor recirculating pumps to slow speed (at this point in time, the reactor was already scrammed, RHR was in the suppression pool cooling mode, and one recirculating pump was off; the other was already in slow speed).

At approximately 2:10 am, a plant operator reported to the control room that a massive leak existed at the 36 inch circulating water inlet to the heater bay at the 620 foot level. As a result, the Unit supervisor ordered the "A" and "B" circulating water pumps secured. In accordance with Procedure No. PEI-13, reactor pressure was being controlled by opening the steam bypass valves. These valves were used until the reactor pressure had decreased to approximately 700 psig. At 2:24 am, the outboard Main Steam Isolation Valves (MSIVs) were closed because of the imminent complete loss of condenser vacuum. The "C" circulating water pump was also secured. Reactor pressure control was then transferred to the Safety Relief Valves (SRVs).

An ALERT was declared at 2:59 am by the on duty Shift Supervisor (SS) based on the then current plant conditions, the loss of the N71 system due to the pipe rupture, and the flooding in the Intermediate Building, Auxiliary Building and the Turbine Building heater bay.

From 2:22 am to 6:57 am, 50 individual manual SRV cyclings occurred. Reactor Core Isolation Cooling (RCIC) was used from 2:25 am to 2:35 am to augment the SRV pressure control. As a result of the above actions, reactor pressure was reduced from 674 psig to 128 psig. Head spray was then used to continue deceasing reactor pressure.

Both Residual Heat Removal (RHR) pumps "A" and "B" were operating in the suppression pool cooling mode for all of the SRV cyclings. The "A" RHR pump was eventually shifted from suppression pool to shutdown cooling at 7:37 am to assist in Reactor Pressure Vessel (RPV) cooldown.

The Motor Driven Feed Pump (MFP) and RCIC were used for reactor level control for most of the transient. The MFP subsequently failed to restart after its 15th level 8 (219 inches above active fuel) trip at 3:59 am. Level 8 also causes a scram signal if the mode switch is in the "run position", closure of the RCIC turbine steam supply and the HPCS injection valves, and trips of the MFP, reactor feedpump turbine, and the main turbine. RCIC was then started for level control at 4:04 am. (Note: At 2:08 am, RCIC was manually initiated and injected to the vessel for approximately 1 minute before subsequently tripping on level 8. RCIC was not used for level control again until the MFP failed.) Reactor level cycled to greater than level 8 nineteen times during the RPV cooldown due to void formation and collapse following SRV cyclings. Once reactor pressure had been reduced to less than 350 psig, a reactor feed booster pump was placed on the low flow controller to control reactor vessel level. Throughout the remainder of the transient, RCIC was used for pressure control.

At 11:51 am, on December 22, 1991, the Alert was terminated and a recovery phase entered.

2.3 Precursors to The Event

At the time of the event, approximately 1:50 am, on December 22, 1991, the only plant transient in progress was a reactor power increase from 99% to 100% power, which had no impact on the N71 system. Prior to the event, no other plant evolutions involving the N71 system were in progress. The N71 system had been operated steady state, with no circulating water pump shifts since November 24, 1991. Based on the team's review of plant logs and interviews with operators, no ongoing activities which could have been precursors to the pipe rupture event were identified.

2.4 Operator Response

To determine what actions the operators took in response to the event and the suitablility of these actions, the team reviewed plant logs, the Post Scram Restart Report (1-91-2), appropriate plant emergency and off-normal procedures, and interviewed the operators involved in the event.

On December 22, 1991, prior to the event, the operators were performing routine functions with no major evolutions or plant transients in progress. The initial event information that the operators noted were the following alarms and indicators:

- Process computer alarm - Circ. Water Pump A, B, C Outlet Pressure Low

- Annunciator No. 1H13-P870 - Circ. Water Pump Suction Chamber Low

- SAS report from F&S Computer - Motor and Diesel Firepumps start. Unit 1 Startup Transformer Deluge

The initial alarms associated with the N71 system were not considered unusual. These alarms can be caused by high winds or sluggish reaction of the cooling tower makeup valves (Note: The previous weekend, the plant experienced high winds which caused spurious alarms related to the cooling tower basin).

The report concerning the startup transformer deluge was initially thought to be a separate problem. The SS dispatched plant operators to investigate the cause for the deluge. An operator reported back that there was a large water leak in the vicinity of the Unit 1 Turbine Building heater bay adjacent to the transformer yard.

With reports of a large leak and observation that the level of the cooling tower basin was decreasing, the SS surmised that there was a leak in the N71 system. The initial action taken was to try to isolate the leak; but, after receiving updated information from the field that the break was at the N71 water inlet to the Auxiliary Condensers, the SS made a decision that the leak was not isolatable.

Realizing that loss of the main condenser as a heat sink was imminent, the SS ordered a fast reactor shutdown. The reactor was scrammed approximately 15 minutes after the first indication of a N71 problem. After the scram, subsequent actions taken included shutting down all but one of the circulating water pumps, establishing suppression pool cooling, transferring pressure control to SRVs, securing the remaining circulating water pump, and shutting the MSIVs. The deluge on the startup transformer was also secured after verifying that there was no fire. These actions ensured stability of the reactor pressure control prior to the loss of the normal heat sink, established the support systems to handle SRV actuation so that containment design parameters were not challenged, isolated the motive force of the leak, isolated the main steam supply to the main condenser which had no cooling vacuum, and removed an unnecessary challenge to the reliability of the off-site power supply (deluge of the startup transformer).

Once the MSIVs were shut, the operators utilized the SRVs, RCIC and the MFP for reactor level/pressure control during the plant cooldown. While utilizing the SRVs for pressure control, the plant experienced six level 3 actuations and 19 level 8 actuations. Each of the level 8 actuations led to a trip of the MFP. These level actuations were caused by the shrink and swell effect on the reactor vessel as the SRVs actuated. In discussions with the plant operators, the team surmised that the shrink and swell were expected but that the magnitude of the level change was larger that expected.

Factors affecting the magnitude of level changes include:

- The length of time the SRV is open, which for a given decay rate determines the magnitude of the pressure change.

- The status of the feedwater at the time of the actuation. If feedwater is available and in automatic control, some buffering effect is observed on the level transients when the SRVs are actuated.

Though the level swings were larger than expected, the operators were able to maintain control of the cooldown throughout the evolution. On reviewing the ERIS plots of RPV parameters, the team noted that as the cooldown progressed, the operators were able to minimize the level swings by minimizing the SRV actuation times and by adjusting feed flow prior to the actuation in anticipation of level swings.

During the event, several equipment failures occurred which complicated the plant recovery. Throughout the event, operators properly prioritized their actions and concentrated on placing the plant in a cold shutdown condition. The specific failures are discussed in Section 3.3 of this report. Operator action in response to the equipment failures was to enter the off-normal instructions for the specific systems to recover from the failures. The following off-normal instructions were entered or referenced during the event.

- ONI-B21-4 Isolation Restoration
- ONI-B33-? Loss of One or Both Recirculation Pumps
- ONI-C71-1 Reactor Scram
- ONI-C71-2 Loss of One RPS Bus
- ONI-D17 High Radiation Levels
- ONI-N32 Main Turbine Trip
- ONI-N62 Loss of Condenser Vacuum
- ONI-P52 Loss of Service and/or Instrument Air
- ONI-R22-2 Loss of Non-Essential 13.8kV or 4.16Kv Bus
- ONI-R23-2 Loss of Non-Essential 480V Bus
- ONI-R25-2 Loss of Non-Essential 120V Bus

During the event, Plant Emergency Instructions (PEI) No. PEI-B13, "Reactor Pressure Vessel Control" and No. PEI-T23, "Containment Control" were entered. PEI-B13 was entered on several occasions when reactor vessel level dropped to level 3 during plant depressurization and cooldown. PEI-T23 was entered on high suppression pool level and temperature following SRV cycling for pressure control.

Based on discussions with plant operators and review of the PEIs, no deficiencies were identified in the effectiveness of the PEIs to guide the operators in keeping the reactor vessel and containment in a safe condition during the event.

Base on review of this event, the team determined that operator response to this event was prompt, effective, and in accordance with plant procedures. The operators quickly evaluated the indications and took prompt action to place the plant in a safe condition. Specific strengths included the following:

- Good communications and team work between operators in the field and the control room enabled the SS to properly evaluate and deal with the event.

- Good prioritization of activities by the SS which prevented overall actions from being diverted to individual equipment problems.

- Good use of procedures assisted in the prioritization and combating of individual equipment problems.

The team concluded that the operators safely responded to a challenging plant event and that their actions were indicative of a strong knowledge of plant systems and plant operating procedures.

During the teams's interview of operators, one reactor operator (RO) indicated that the resident inspector (RI) encumbered the licensed operators from responding to the event by asking too many questions during inopportune moments when the operators were busy responding to the event. In addition, the licensee indicated that the NRC had requested the Shift Supervisor (SS) to man the phones and provide information regarding the event. Consequently, the licensee contended that the SS was encumbered from giving his full attention to the event and activation of the Technical Support Center (TSC) was slightly delayed. Pending review in a subsequent inspection report, this was considered an open item (50-440/91026-01(DRS)).

3.0 Inspection Results

3.1 Circulating Water Piping

3.1.1 Fiberglass Piping

(1) Performance History and Maintenance

After initial construction of the fiberglass circulating water system lines, leakage of ground water into the pipe was observed. This was due to various areas of cracking and delamination of the pipe material. In 1982, the system was analyzed, the defects were identified, and repairs and modifications were made. During the 1982 review it was discovered that the two supports under the steel portion of each of the supply and return lines (near the steel flange to fiberglass pipe flange interface) were sliding supports. It was further discovered that there were no anchor points for the steel segments of these lines. It may have been assumed by the steel line designers that the flange-to-flange connection connecting the fiberglass pipe buried in the ground served as an anchor. However, the fiberglass pipe cannot withstand any significant external loading or deflection. Hence, without any engineering analysis, only the sliding support (nearest the elbows) was welded to the base plate to become a "temporary anchor". It was recommended that a permanent solution to this be made. The field change was inadequately documented, reviewed, and accepted by Gilbert Commonwealth (the Architect Engineer) and it became a permanent modification.

(2) Material Condition of Affected Piping

A visual inspection of the inside of the piping had been performed during normal refueling outages which resulted in minor repairs being made. However, the inspection was accomplished by a work order without a written procedure and it was left up to the inspector ("skill of the craft") to determine what acceptance criteria to use. Also, the affected supply elbow could not be adequately inspected because it is at the end of an approximate 12 foot vertical section of pipe. The return elbow is even further away from the inspector's view. Therefore, the section of piping that was not inspected subsequently failed. The licensee intends to inspect the vertical portion of the pipe and the elbow during refueling outage number 3 (RFO3) using scaffolding or rope ladders.

To repair the failed fiberglass elbow, a similar flange and elbow that was installed on Unit 2 was cut out and removed. Fiberglass was added to the elbow to strengthen it. Also, additional material was added to eliminate any possible material degradation concerns. The return elbow will be evaluated to determine if any reinforcement of this elbow with additional fiberglass is necessary.

3.1.2 Steel Piping

The fiberglass elbow which ruptured was attached to an approximately 90 foot run of 36 inch carbon steel piping. The mating surface was a bolted flange sealed with a rubber O-ring. The majority of the force from the break was absorbed by the N71-H013 support in which all four 3/4 inch studs failed in the tension mode. Upon failure of the support, the 36 inch steel piping displaced upward approximately 7 inches. This was evident due to the deformation of a construction rigging hanger that had been left in place. (The angle iron on the construction hanger was deformed at the point of contact.) Metallurgical examination of the failed support bolts also revealed a bending deformation of the bolts prior to failure; however, lateral displacement appeared to be less than one foot as indicated by markings on the concrete pad. Evidence of minimal pipe whipping was noted with no damage to the piping. The licensee performed magnetic particle examination (MT) of support welds Nos. H013 and H027 and field welds Nos. FW-01 and FW-02. Visual examination and MT of the piping and hangers revealed no indications of damage. The team observed the condition of the steel piping as described above and concluded that no damage to the steel piping configuration was evident.

3.1.3. Piping Supports

(1) Material Condition and Damage

The pipe supports for the 36 inch auxiliary circulating water supply line (steel piping) were designed as sliding supports. The two supports adjacent to the steel-fiberglass pipe connection were attached to the top of the roof of the Turbine Building heater bay. The heater bay roof is at ground level at this section of the pipe run. These supports are non-safety related and were designed as dead weight supports. Due to the attachment of the fiberglass pipe to the steel piping, it was necessary to change the design of the first support (No. N71-H013) from a sliding support to a rigid support. This was required as the fiberglass piping could not withstand the cyclic movement permitted by the sliding support. A modification to the N71-H013 support was made by welding the sliding plate of the support to the attachment plate which was anchored by four 3/4 inch HDI Hilti drop in anchors and 3/4 inch by 6 inch full threaded studs. This modification was documented on Engineering Change Notice (ECN) 9004-45-534, dated July 8, 1982, with the reason for the change documented as interference instead of indicating that a design change was needed. This may have contributed to the inadequate review it received by Gilbert Commonwealth.

The most probable cause of the failure of the 36 inch auxiliary circulating water supply line was the failure of the N71-H013 support. This was due to improper design which led to improper installation. As a result, the anchors were never properly preloaded (torqued) or that they lost their preload. Evidence of the support failure causing the pipe rupture was reported in the metallurgical analysis of the N71-H013 support anchor bolts. The following observations were made:

- Two bolts (NE and NW corners) failed below the lower nuts.
- Two bolts (SE and SW corners) failed between the nuts, within the support plate.
- Three of the four bolts had threads in between the nuts hammered flat.
- All four bolts failed in the ductile mode with significant plastic bending.
- No signs of fatigue on the fracture surface were found.
- Fatigue cracks were found at other locations on the bolts with indications of corrosion assistance in the root of the cracks.
- An inspection of the nuts revealed that only one nut of each pair was in contact with the plate.
- Chemical analysis confirmed that the bolts and nuts were manufactured from low carbon steel.

The flattening of the threads appeared to be caused by the looseness of the nuts causing the N71-H013 support to move within the attachment plate stud holes. This looseness in the N71-H013 support permitted the entire support to displace and hammer the threads of the studs flattening them. This oscillating motion may have loosened the studs or they may have not been torqued to proper values during installation. Whatever the cause of the loose bolts, the oscillating movement apparently fatigued the fiberglass pipe elbow at the fiberglass elbow to fiberglass pipe joint and caused the leak and catastrophic rupture which in turn caused the bolt to fail completely. The steel supports did not sustain any structural damage. The welds of both N71-H013 and N71-H021 were magnetic particle examined with no defects observed.

(2) Corrective Action

The licensee's corrective action report (DCP 91-0288) modified supports 1N71-H013 and 1N71-H021 to significantly increase anchorage strength and resistance to loosening from sustained vibrating loading. The new design incorporates 3/4 inch diameter Drillco Maxi-Bolts which have a ultimate tensile strength approximately three times that of the studs that were installed. The team reviewed the DCP and was concerned that this analysis only analyzed for static or deadweight conditions. The team was also concerned that since the support was originally modified by welding to make it a rigid anchor, apparently without the benefit of a design analysis, that the new design should receive a more rigorous analysis.

Based on their review of the DCP, the team requested that the licensee perform a dynamic analysis to assure the modification provides the necessary rigidity and strength to prevent failure of the fiberglass piping due to operational loads. The licensee is to perform this analysis within 30 days of plant restart. In the interim, at the request of the NRC, the licensee has instrumented the piping and the 1N71-H013 support to monitor for movement during operation. This monitoring will continue until the analysis of the piping support is completed. On January 3, 1992, the NRC closed the December 24, 1991, CAL and issued a new CAL (attachment 4) which clarified conditions to be met prior to the restart of the plant, including reporting requirements.

3.2 Flooding

3.2.1 Amount of Water and Flood Path

Water flooded the ground surface and entered manhole No. 20 of the plant underdrain system which had been left uncovered. Discharge from the break ceased when the circulating water pumps were shutoff within 34 minutes of the break. The maximum estimated out flow rate at the start of the break was approximately 250 thousand GPM and decreased as the plant was brought down in power and the circulating water pumps were shutdown.

Per calculation No. N71-7, approximately 2.9 million gallons were pumped from the pipe break. A small percentage reached the following locations through the floor and equipment drainage system:

(1) Water on floors of the Auxiliary Building at elevations, 574 feet and 568 feet, Intermediate Building at the 574 foot elevation, and Control Complex Building at 574 feet and 599 feet elevations.
(2) Mud and puddles in the Auxiliary Boiler Room at the 620 foot elevation.

(3) Mud and puddles in the Heater Bay at the 620 foot elevation and minor leakage through ceiling plugs at the 600 foot elevation.
(4) The Emergency Service Water Pump House floor was covered with water.
(5) The Service Water Pump House switchgear Mezzanine had silt on the floor.
(6) There was some leakage at the Unit 2 Annulus area.
(7) Unit 2 Auxiliary Building at the 568 foot elevation.

3.2.2 <u>Design of Underdrain System</u>

The underdrain system beneath the plant was constructed to prevent excessive uplift pressures from developing beneath the buildings as a result of an extremely high natural ground water table. It consists of a porous concrete blanket with a circuit of 12 inch diameter porous concrete pipes beneath the buildings to collect and convey the ground water to manholes, and two systems to remove the water from the manholes to discharge to the lake.

One discharge system uses pumps located in the manholes, and the other uses higher elevation pipes to convey the water by gravity to the lake. The pumped discharge system is designed to convey water through the porous concrete blanket and pipes to collection manholes. The water is then discharged from the manholes by submersible pumps, maintaining the water level between elevation 566 and 568 feet.

The gravity discharge system, which consists of 36 inch to 48 inch pipes connecting the manholes, is some 20-25 feet above the underdrain blanket. It provides an alternate flow path for drainage in the event of a complete failure of all the pumps. This system ensures that the water level never exceeds elevation 590 feet. It incorporates a gravity outfall and is designed to handle a total flow of 60 thousand GPM for two units, 30 thousand GPM for each.

3.2.3 <u>Conformance with USAR Assumed Magnitude and Path</u>

Two design flood breaks were considered in the USAR. The first was a circumferential break of the main circulating water piping underground on the East side of the site which had a resultant flow of 18 hundred GPM to the underdrain system.

The second case assumed pipe break was a circumferential break of the main circulating water piping at an expansion joint inside the turbine building coincident with a crack in the turbine building basemat. This scenario put 30 thousand GPM into the plant underdrain system. This amount was used as the worst case design break for the system. The system is designed to fill up after approximately 3 million gallons of water have entered. The remaining water would flow to the lake by gravity.

The path that the water took when it entered the plant (through electrical conduit) was not specifically considered in the USAR; however, it was bounded by both of the design basis floods. Further, the design basis flooding in the Auxiliary Building is 20 inches above the floor without any safety significance. Flooding higher than 20 inches would have affected the safety function of safety related electrical and mechanical equipment. In this case, the water reached a level of 6 inches. The following is a description of the actual flooding that occurred during the event:

(1) External

With manhole No. 20 open, a pool of water formed which completely filled up the manhole (the cause for the high water level alarm). The gravity discharge piping directed 30 thousand GPM towards the lake. The excess water also flowed toward underdrain manholes No. 8, No. 19, and No. 23. Eventually, the water traveled through the porous concrete pipe and then to the porous fill beneath the buildings, but this process was relatively slow. The system disposed of the entire volume before the entire underdrain system filled to elevation 590 feet. Thus, the water level was kept below that assumed for the design basis turbine building circulating water pipe break.

The underdrain system was designed with gasketed, water tight covers. The design did not consider a manhole being left uncovered. If manhole No. 20 had been covered, the outflow from the break would have run off following the slope of the ground surface to the lake, except for the water that seeped into the ground. This seepage rate is extremely low due to the three feet of impervious fill placed over the site to reduce infiltration at the ground surface. The resulting inflow in this case would be much lower than for the design basis in-ground circulating water pipe break.

(2) Internal

Due to the rise in the water level in the underdrain system above elevation 568 feet, water could have leaked through piezometer tubes. These were installed in the basement floors of buildings to monitor the water level in the underdrain system. Some covers were either left off or were loose allowing water to enter.

Water entered through water stops provided between building foundation mats and the waterproofing membrane used to seal the 3 inch space between individual buildings.

Water entered the Heater Bay Building in the vicinity of the break through doorways and at grade level through concrete hatch plugs.

It appears that the majority of water came from electrical manholes No. 1 and No. 4 which were in the flooded area. These have had a history of leakage during rains. They were not designed for water tightness against standing water. The plastic conduits in these manholes provided a path directly to the buildings where the cables enter.

In-leakage was not unexpected. However, the amount of in-leakage was not anticipated within the buildings and overwhelmed the floor drains so that some of the lower floor drains backed-up with contaminated water spilling on the floors. This caused some minor contamination problems. However, the water level only reached less than one half of the design flooding height of 20 inches and caused no other problems.

3.2.4 Effects of Flooding

(1) Electrical Equipment

Electrical manholes Nos. 1, 2, 3, 4, and 7 were flooded during the event, as were security manholes Nos. 60, 66, and 67. Water leaks into the buildings were observed from some of the manholes. Water leaking from manhole No. 3 into the essential service water pump house (ESWPH) caused damage to electrical equipment. Water entering the ESWPH through a series of conduits to motor control center (MCC) No. EF1A12 ran down a cable into compartment "C" of the MCC causing a 120 volt control transformer to short and possibly damaged Rosemount transmitter 1P45-N090A. The transformer and transmitter have been replaced.

No other equipment damage or malfunction related to the event was identified.

(2) Mechanical Equipment

Inspections of the flooded areas revealed limited flooding which did not effect mechanical equipment. The team observed the flooded areas in the Auxiliary and Intermediate Buildings which experienced the worse flooding. No water was present at the time of inspection but water marks and sludge (accumulated dirt and corrosion deposits) were evident. Water level marks on walls and equipment pads were approximately 4 to 5 inches in the worst case. No mechanical equipment was observed to have water marks or evidence of flooding. Mechanical equipment in the flooded areas are mounted on pads. The water did not exceed the height of these pads as evidenced by the water marks on them.

(3) Extent of Contamination

To determine the extent of contamination as a result of the N71 system pipe break, the team toured the contaminated areas, interviewed health physics (HP) personnel, and reviewed logs and HP survey reports. The contamination was caused by the backup of the plant floor and equipment drain system. The cause of this backup is discussed in Section 3.3.7 of this report.

When the drain system backed-up, water was ejected from the drains and spread out in the basement levels (574 foot elevation) of the Intermediate Building, the Unit 2 Auxiliary Building, the Control Complex, and the Radwaste Building. These normally dry areas received an accumulation of water of up to six inches. While conducting a walk down of these areas on December 22, 1991, the team noted a build up of approximately 2 to 3 inches of sludge around the drains in the Intermediate Building. The sludge was forced out the contaminated floor drains when the drains backed up.

The on-contact dose rate reading of the sludge was a maximum of 40 mrad/hour in the Auxiliary Building and up to 5 mrad/hour in the other buildings. The resultant surface contamination of the flooded areas varied throughout the plant dependant on the initial contamination of the respective floor drains. The highest surface contamination detected in the Auxiliary Building was 40k DPM/100cm² at the North and East of the 574 foot elevation. The highest surface contamination in the Intermediate Building was 30k DPM/100cm² by the Unit 1 control rod drive pump filter area on the 574 foot elevation. Surface contamination in the other plant areas that flooded varied from 1 to 15k DPM/100cm².

Contamination of the Unit 2 Auxiliary Building occurred as a result of contaminated water flowing from the 574 foot elevation of the Intermediate Building underneath a security door separating the two areas. Some of the water collected on the floor while the rest flowed into a sump located adjacent to the door. The contaminated water that collected in this sump was then pumped to another sump in the Unit 2 Power Complex. When this sump filled up and automatically pumped out, the contaminated water was release to a drainage system outside the plant. This resultant release is discussed in Section 5.3.2 of this report. Surface contamination of the Unit 2 Auxiliary Building floor by the sump varied from 2 to 20k DPM/100cm².

The Unit 2 Annulus area also received some water from the Intermediate Building with no detectable contamination being reported. Nevertheless, action was taken to pick up the water. The team inspected the Unit 2 annulus region and determined that the water stagnated in this area and that no natural release path for this water existed.

Decontamination efforts to clean up the affected areas were commenced on the day of the event, with all major passageways being cleaned for normal access by December 24, 1991. At the conclusion of the AIT on December 29, 1991, decontamination of normally non-accessible areas was still in progress.

The team observed licensee control of contaminated areas and their decontamination efforts. The team concluded that the contamination was well controlled and that the decontamination effort was thorough and well organized.

(4) Offsite Releases

On December 22, 1991, slightly contaminated water was discharged to Lake Erie through an unmonitored pathway. The water, originating from the backed up floor drains in the Intermediate Building 574 elevation, passed underneath a security door and into the Unit 2 Auxiliary Building at the same elevation. The majority of the water then flowed into a sump adjacent to the door, with the rest of the water covering approximately 600 square feet of the floor in front of the door. The Unit 2 Auxiliary Building floor surface contamination was 2-3K DPM/100cm². The total volume of water that entered Unit 2 was 2000 gallons based on licensee calculations. Of the 2000 gallons that entered the Unit 2 Auxiliary Building the licensee estimated that approximately 300 gallons of this water were pumped out by a sump pump automatically to a Unit 2 Turbine Power Complex sump via a rubber hose since the Unit 2 radwaste system was not operational. From there it was eventually pumped off site through an unmonitored release path. The rest of the water was either picked up during floor decontamination or was pumped to the Unit 1 Intermediate building sump for processing through Rad Waste.

The water that collected in the turbine power complex sump was automatically pumped out by a sump pump which discharges to a roof drain on the Unit 2 Turbine Building, which drains to one of the South storm drains. This branch of the storm drains leads to the large sediment pond and eventually to Lake Erie.

The activity level in the Unit 2 Auxiliary Building sump was measured several times. The results of the survey giving the highest identified Co-60 at 1.46 E-6 μc/ml and Mn-54 at 3.14 E-7 μc/ml. Samples of the Unit 2 Turbine Power Complex sump were obtained on December 23, 1991 and detectable activity above the effluent Low Level Dose (LLD) levels were found. Also, samples were obtained from the water leaving the storm sewers, from sediment at the exit of the storm sewers, and from water from the holding pond. These three samples were sent to the environmental laboratory for further analysis. Results are expected in 2 weeks.

The licensee took the following actions to prevent a recurrence of the release:

- The hose was removed and sampled for contamination. It will not be re-installed.

- A 3 to 4 inch barrier wall is being considered for installation in front of the security door between Intermediate Building and the Unit 2 Auxiliary Building.

Pending the results of the water and sediment samples that were sent to the environmental laboratory for analysis and based on the low levels of Co-60 and Mn-54 identified in the Unit Auxiliary Building sump and no detectable activity in the Unit 2 Turbine Power Complex sump, the radiological consequences of this release appeared to be small.

3.3 Equipment Failures

3.3.1 Failure of the Scram Discharge Valve (SDV) to Drain

Subsequent to the initiation of the manual scram of the reactor due to the circulating water break, the scram discharge valve failed to open and allow the scram discharge to drain. Inspection of the Hammel Dahl valve revealed the failure of the coupling between the operator and the valve stem. The failure of the stem connector was similar to failures reported in General Electric Nuclear Services (GE) Information Letter (SIL) No. 442 issued in

1985. The attaching bolts which clamped the connector together were loose and subsequently did not engage the stem and actuator threads firmly. This apparently caused the separation of the valve stem and actuator stem when the valve was actuated. The bolts on the position indicator and stop cam were also observed to be loose. The apparent cause of the failure was improper assembly.

The licensee consulted with GE who indicated that no other BWR has reported problems with the stem coupling engagement for these valves other than those reported in SIL 442. The licensee has installed a new coupling in accordance with the SIL 442 requirements and initiated changes to the applicable vendor instruction manual which included the following steps:

- Assure coupling threads match stem threads (both ends), visually verifying no damage to either coupling threads or stem threads prior to assembly.

- Assure coupling bolt is inserted through bored (unthreaded) hole and threaded into the threaded hole in the other coupling-half.

- Assure coupling threads and stem threads are engaged prior to torquing the coupling bolt.

- Torque the coupling bolt to 15 ft-lbs, ensuring that the coupling halves are clamped against the stems, <u>prior</u> to installing the nut and lockwasher and subsequently "snugging" the nut.

To improve long term reliability, an Engineering Design Change Request (EDCR 91-0289) has been initiated as a vehicle to evaluate potential design improvements to the stem coupling for these valves.

The consequence of the failed scram discharge drain valve stem connector is not safety significant in this case, as the failure of the steam connector results in the valve repositioning to the fail safe position. All control rods are inserted with the scram signal. With the failure of the scram discharge drain valve stem connector the valve remains in the closed position and the control rods cannot be moved. However, the Emergency Operating Procedures (EOPs) require the valves to be reopened during an Anticipated Transient Without Scram (ATWS). This could not have been done had there been an ATWS.

3.3.2 <u>Failure of [illegible] to Transfer</u>

Upon plant shutdown ([illegible]e trip), the plant auxiliary loads are auto transferred from plant auxiliary to plant startup power sources. This is accomplished automatically by (1) opening 13.8kV breaker L1102 and closing breaker L1006 and (2) opening 13.8kv breaker L1202 and closing breaker L1009. Both of these breaker's auto transfer schemes are driven by the same relay logic. During the event, the L1203 to L1009 transfer properly occurred while the F1102 to L1006 transfer failed. Upon inspection, the L1006 closing springs were found to be discharged. All spring charging switches and fuses were found in the proper positions.

Maintenance personnel inspected breaker L1006 and determined that the closing spring was not charged. Further investigation revealed that a defective control relay prevented the charging motor from charging the closing spring. The control relay was replaced and breaker L1006 tested to verify its proper operation.

The failure of the bus transfer was not a result of the pipe break event since the transfer would have f...ed to occur the next time an automatic transfer from the auxiliary trans... ...r to the start up transformer was initiated.

3.3.3 Damage Assessment Due To Repeated Starts of MFP

The MFP breaker was set in the AUTO start mode at the time of the event. When the turbine driven feed pumps trip, the MFP will start and feed water into the reactor vessel until the vessel high level trip signal stops the pump. When the high level alarm clears, the operator can reset the trip signal and the pump will automatically restart. The MFP then ran from 1 to 20 minutes repeating the cycle. This trip-reset action occurred 15 times in less than 2 hours. On the 16th trip reset, the MFP did not automatically start due to failure of the electrical breaker.

The licensee contacted the motor manufacturer's representative who stated that the motor had exceeded the recommended 2 hot starts. It was recommended that the motor be meggered and if the megger readings were acceptable, and the running motor had no unusual noises, the motor be considered acceptable for continuous operation.

The licensee meggered the motor windings and recorded a reading of 10,000 megohms which exceeds the manufacturer's and IEEE-43-1974 minimum requirements of 14 megohms. The MFP motor showed no signed of damage due to the excessive number of hot starts. The licensee plans to do vibration testing of this motor upon restart to further assure that there was no damage during the event.

The licensee's engineering review of the breaker control logic did not reveal any anomalies that would explain the breaker's failure to close on t.. 16th close actuation. Licensee maintenance personnel cycled the breaker using circuit breaker testing equipment. The breaker operated satisfactorily. The breaker was then disassembled and the contacts inspected per manufacturer's instructions The breaker was reassembled, returned to its switchgear cubicle and operated several times in the test position. No root cause of the breaker failure to close has been determined. The licensee will monitor the breaker operation during MFP testing at plant restart.

The team concluded that the most probable cause of the breaker failure were cumulative heating effects caused by the repeated motor starts. The team also concluded that the failure of the pump to start on the 16th try was not safety significant because the plant still had RCIC and HPCS available.

3.3.4 Cause of Startup Transformer Deluge

During the event, the startup transformer deluge system actuated. The transformer is near the pipe break. When the comparatively hot (80-85°F) water hit the cooler transformer, the transformer's rate of temperature rise sensors detected a rapid temperature increase which actuated the deluge system. There was no damage to the transformer and the transformer protection equipment performed its design function.

3.3.5 Instrument Air Anomalies

During the event, the instrument air system could not maintain air pressure above 86 psig with a scram signal in and the SRVs being cycled. The Unit 2 Instrument Air Compressor appeared to trip off-line without generating any alarms.

The team determined that the operation of the instrument air system was normal for the above conditions. When the system is set in the AUTO ON-OFF mode, the pressure will decrease to below the low pressure setpoint prior to the start and loading of the air compressor. After the pressure reaches the desired level, the compressor unloads.

By design, only one air compressor is required to supply adequate make-up air for all system needs. The Unit 2 air compressor tripped off without alarms because it was not needed. Since the Unit 1 air compressor was always loaded first, the Unit 2 air compressor was very seldom loaded and shut itself off per the control logic; therefore, there were no alarms generated.

3.3.6 Backup of the Floor Drains

As discussed in Section 3.2.3 (2), the floor drains backed up due to the large quantity of water flowing into upper drains. The root cause was that the drain piping was not designed for such a large inflow of water at upper elevations in the buildings.

The licensee has strengthened administrative controls to assure that inspection manhole covers are kept closed and that piezometer caps are on and tight. Conduits that conducted water into the building were sealed. Improvements are also being considered in regards to leak tightness of electrical manholes.

4.0 Event Classification and Reporting

The licensee classified the event as an ALERT in accordance with Tab L. II.1 of OM15A, "Emergency Plan for Perry Nuclear Power Plant." Tab L.II.1 of the licensee's Emergency Plan specifically requires that an ALERT be declared if ground water level rises above 590 feet as indicated by local indication at the majority of the underdrain manholes. Should the ground water level exceed the 590 feet elevation, safety-related structures would be placed in jeopardy due to the hydro-dynamic loading that would result. Ground level at the Perry site is nominally at an elevation of 620 feet.

During the event, annunciators in the control room indicated that the underdrain system was being overwhelmed by the large volume of water escaping from the pipe break. Additionally, the shift supervisor concluded that additional staffing would be required to adequately respond to the event. Given these considerations, the shift supervisor determined that an ALERT should be declared.

The team reviewed the specific circumstances surrounding the event, discussed the event with plant operators and other licensee personnel, and reviewed operator logs and Emergency Coordinator logs. Based on this review, the team concluded that the status of the underdrain system was in question during the event and declaration of an ALERT condition was appropriate. The team also concluded that all required notifications were made in a timely manner in accordance with the licensee's Emergency Plan.

The licensee stated that a self-critical assessment would be completed to evaluate personnel performance and staffing, NRC interface (HQ and Resident staff), and adequacy of the Emergency Plan relative to the actual event and circumstances involved. The license will communicate the results of this assessment with the NRC Region III Office.

5.0 Safety Significance

During the event, some fraction of the water that was discharged through the break entered the underdrain system through open manhole number 20 and some of the water drained into electrical and security manholes. It is likely that the water that flooded manhole number 20 overwhelmed the underdrain and gravity drain system at that location for a short period of time, but the nominal groundwater level throughout the site remained well below the design basis level of 590 feet. The amount of water that entered the Turbine Building, the Auxiliary Building and the Intermediate Building was within the bounds of the flood analyses that were completed for these locations and no safety-related equipment was effected. Although the event did result in an unmonitored release from the Unit 2 auxiliary building sump to Lake Erie, the release was a very small fraction of the regulatory limits. Therefore, the event in and of itself was not safety-significant; however, response to the event required a plant shutdown and consequent unnecessary actuation of safety equipment. The licensee should specifically identify any other critical fiberglass/carbon steel interfaces that exist in the plant and verify that the installation is being properly maintained and that the design is adequate.

6.0 Conclusions

After completing the AIT Charter, the team was able to make the following conclusions:

(1) The AIT concluded that the root cause of the failure was inadequate design of a support adjacent to the auxiliary circulating water system pipe elbow that failed. The licensee did not implement recommendations in a 1982 consultant's report relative to the repair and modification of this pipe support. Instead, a temporary repair was made to address problems

experienced during construction and was allowed to become a permanent modification without adequate design analysis. The specific failure mechanism involved a loosening of the pipe support anchor bolts which, in turn, permitted excessive movement of the fiberglass circulating water pipe elbow. Potential contributors to failure may also have been a manufacturing flaw which existed in the fiberglass elbow or an incorrectly installed fiberglass pipe splice. Catastrophic failure of the pipe prevented drawing definitive conclusions on this point.

(2) No significant operational or safety parameters were approached or exceeded.

(3) Off-site releases were minimal and will be included in the licensee's annual report due to the low level of the release.

(4) Although the root cause of the failure of the MFP breaker on the 16th start was not determined, its most probable cause was due to the heating effects of the consecutive starts.

(5) Failure of the SDV valve and the failure of Bus No. L11 to transfer were not related to the auxiliary circulating water pipe break.

(6) The deluge of the startup transformer was caused by the pipe break; however, its internal protection circuits performed as designed.

(7) The overflow of the drains was due to the pipe break. This caused some contamination of basement areas of the plant; however the resultant flooding was limited and did not reach a level that affected the operation of safety related equipment.

(8) The operators safely responded to a challenging plant event and their actions were indicative of a strong knowledge of plant systems and procedures.

(9) While the modification to the auxiliary circulating pipe support is adequate for short term operation, a rigorous analysis of the dynamic loads is essential. Further, the pipe should also be closely monitored to ensure that no significant pipe movement is occurring in the near term.

7.0 Charter Completion

The team completed the Charter on December 29, 1991, and the AIT was disbanded after a teleconference with RIII managers.

8.0 Exit Interview

The team met with licensee representatives (denoted in attachment 3) on December 29, 1991, and summarized the purpose, AIT charter items, and findings of the inspection. The team discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the team during the inspection. The licensee did not identify any such documents or processes as proprietary.