U.S. NUCLEAR REGULATORY COMMISSION
REGION III

Report No. 50-341/93029 (DRS)

Docket No. 50-341 License No. NPF-43

Licensee: Detroit Edison Company
6400 North Dixie Highway
Newport, MI 48166

Inspection of: Fermi Unit 2
Newport, Michigan

Conducted: December 28, 1993 through January 19, 1994

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Inspection Summary

Inspection from December 28, 1993, through January 19, 1994
(Report No. 50-341/93029(DRS))
Areas Inspected: Special Augmented Inspection Team (AIT) inspection conducted in response to the Fermi 2 Turbine-Generator failure that occurred on December 25, 1993. The review included sequence of events validation, previous turbine generator and support system problems, turbine missle analyses, licensee plans for determining root cause of the turbine-generator failure, and water/oil recovery efforts.
Results: A summary of the AIT results are contained in Section 1.1.2 of the report.

AUGMENTED INSPECTION TEAM

U. S. NUCLEAR REGULATORY COMMISSION

FERMI 2 TURBINE GENERATOR FAILURE

DECEMBER 25, 1993

INSPECTION REPORT NUMBER 50-341/93029(DRS)

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ACKNOWLEDGEMENT

The members of the Augmented Inspection Team acknowledge and appreciate the effort and assistance of Carolyn Crawford, Fermi 2 Resident Office Assistant, who significantly contributed to the development and editing of this report.

DETAILS

1.0 INTRODUCTION

1.1 Executive Summary

1.1.1 Event Description Summary

At 1:15 p.m., on December 25, 1993, the Fermi 2 turbine generator suffered a catastrophic failure causing significant damage to the turbine, generator and exciter. The fire at the generator, exciter, and adjacent areas appeared to be the result of hydrogen leakage, explosion and burn.

At the time of the event, Fermi plant was operating at 93 percent power. The licensee had administratively limited power to 93 percent in early 1993 due to noticeable increases in turbine unitized actuator vibration, and pressure pulsations between the 52 inch steam manifold and first stage inlet to the high pressure turbine. At 1:15 p.m., a turbine trip and reactor scram occurred. The trip was caused by an erroneous turbine mechanical overspeed signal which was triggered by high turbine vibration. Almost simultaneously, multiple turbine vibration alarms, a seismic alarm, and a fire alarm annunciated in the control room. Plant personnel heard a loud noise and felt severe vibrations in the turbine building and control room for approximately one to two minutes. At 1:52 p.m., the licensee declared an Unusual Event and at 1:57 p.m., an Alert was declared. Licensee management representatives immediately responded to the site and provided oversight, direction, and control of recovery efforts. The licensee downgraded from an Alert to an Unusual Event at 5:22 p.m. and at 8:52 p.m. terminated the Unusual Event. Subsequent inspection of the turbine, several hours after the event, identified a hole in the Number 3 Low Pressure (LP) Turbine outer casing.

Within a minute after the initiation of the event, loss of condenser vacuum annunciators alarmed, turbine building roof vents opened, additional fire alarms annunciated, main steam isolation valves (MSIV) closed, motor driven fire pump auto started, and low pressure was noted in the General Service Water (GSW) header. The loss of condenser vacuum caused MSIV closure that resulted in the control room operators controlling reactor pressure using Reactor Core Isolation Cooling (RCIC) and Safety Relief Valves (SRV). Reactor decay heat was removed via the torus and Residual Heat Removal (RHR) system.

Approximately fifteen minutes after the initiation of the event, plant personnel donned self-contained breathing apparatus (SCBA) and entered the turbine building. Heavy smoke and large amounts of flowing water were observed in several areas of the turbine building. Fire brigade members extinguished a small exciter fire and splashed water on the floor onto burning debris. The fire suppression systems located on the second floor of the turbine building directly under the main generator and exciter had actuated. Also, the fire suppression system in the turbine bearing boats had actuated. After ensuring that all fires were extinguished, plant personnel initiated actions to isolate the fire suppression systems.

In addition to water entering the turbine building from the fire suppression systems, water was discharging through severed lines near the main generator and exciter from GSW and Turbine Building Closed Cooling Water (TBCCW) systems. Approximately 500,000 gallons of water was discharged to the turbine building floor before the GSW and TBCCW systems were isolated. Most of this water eventually went to the radwaste building via the turbine building drain system and through direct communications between the turbine building and radwaste building basement; flooding the basement with approximately six feet of water.

Ejected parts of the Number 3 LP Turbine also damaged condenser tubes that allowed Circulating Water (CW) to enter the hotwell. The CW pumps were not secured until approximately two and a half hours after the event initiated. This caused an increase in hotwell inventory that was rejected to the Condensate Storage Tank (CST). This resulted in water in the CST with higher than normal conductivity and chlorides. The source of water for the Standby Feedwater (SBFW) system that maintained water level in the reactor vessel after the event was the CST. Consequently, the water in the CST was pumped to the reactor vessel via the SBFW system resulting in higher than normal conductivity and chlorides in the reactor vessel.

The licensee initiated actions to comprehensively investigate the event and determine causal factors. No personnel injuries occurred. NRC resident inspectors reported to the site to initiate event evaluation and monitor the licensee's response. Photographs depicting the damage are included in Appendix E.

1.1.2 AIT Assessment Summary

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

1. Reactor safe shutdown and safety related/safe shutdown equipment performance was not affected by the event.

2. The licensee has not determined a root cause for the turbine-generator failure. The detailed investigation necessary to determine root cause is not expected to be completed for a number of weeks.

3. The AIT determined that prior to the event, reactor and turbine-generator parameters were normal. There was no indication of impending turbine-generator failure. The team determined, from reviewing vibrational and electrical data recorded prior to and during the event, that failure was not due to turbine overspeed or electrical grid disturbances.

4. The December 25, 1993 event resulted in significant damage to the Fermi 2 turbine-generator system. However, the consequences of the event posed no threat to public health and safety. Gaseous releases resulting from this event were within the range of normal operations. Liquids in the form of oil and water released to the environment as a result of this event contained no detectable radioactive contamination.

5. The AIT concluded that with few exceptions, plant personnel and equipment effectively responded to this challenging event by assuring safe reactor shutdown including the suppression of the turbine-generator system fire.

6. The RCIC Test Return Line Valve failure was attributed to operator error. The licensee had previously determined that the installed valve operator was not capable of opening the valve without first venting the upstream piping. Procedure SOP 23.206 had been revised to include the venting requirement. The operator attempted to open the valve without following the procedure.

7. The "B" Recirculation Pump Discharge Valve failure was attributed to broken wires (three out of four) between the valve's limit switch and torque switch. The root cause of the broken wires is under investigation but is thought to be due to vibrations caused by the valve's close proximity to the recirculation pump.

8. RHR System Warm Up Valve failure was attributed to a defective contactor. Contactor failure was apparently due to either the use of a Cramolin cleaner or the failure to completely engage a spring catch on the contact cover after maintenance activities. Problems with MOV contactors had previously been identified by the licensee and were being investigated at the time of the event.

1.2 Augmented Inspection Team Scope and Objective

As a result of the December 25, 1993, turbine generator failure with complications at Fermi 2, the Region III Regional Administrator, along with the Office of Nuclear Reactor Regulation (NRR) and the Office for Analysis and Evaluation of Operational Data (AEOD) senior management, determined that an Augmented Inspection Team (AIT) should be formed to review and evaluate the event's circumstances and significance.

The AIT Team Leader and three team members arrived on site December 28, 1993, to interview key licensee personnel who were on shift during the event.

The radwaste building basement was flooded with approximately 500,000 gallons of water that was discharged into the turbine building during the event. Additional AIT members arrived on site between December 28, 1993 and January 10, 1994, to support preliminary AIT efforts in assessing the licensee's water management efforts. The NRC Region III Mobile Lab arrived on site January 5, 1994, conducted several confirmatory samples of inplant flooded areas including the radwaste building basement and performed independent measurements of several environmental areas. The full AIT arrived on site January 10, 1994. AIT members are identified on the Cover Sheet of this report. The formal AIT Charter was issued on December 29, 1993, and revised on January 7, 1994 (Appendix D).

The AIT was terminated on Wednesday, January 19, 1994.

2.0 TURBINE GENERATOR FAILURE EVENT

2.1 Sequence of Events

The AIT independently developed an event description and a detailed sequence of events. The time-line was developed through personnel interviews, and by utilizing the computer-generated operational sequential events, various control room chart recorder traces, GETARS data, and operator logs. The AIT also reviewed the sequence of events developed by the licensee's scram investigation team and the Independent Safety Engineering Group. Early in the event, many of the operators' actions and observations were not recorded in the log at the time of the action, but were recorded sometime later based on memory. Therefore, some of these times were not exact. A sequence of events summary is provided in Appendix A. The following is a brief synopsis of the event:

December 25, 1993

1:15 p.m.: a turbine trip and reactor scram occurred with almost simultaneous multiple turbine vibration alarms, a seismic alarm, and a fire alarm. The turbine trip was caused by a turbine mechanical overspeed signal which was triggered by high turbine vibration (See Section 2.2.1 for a discussion of the trip mechanism). Plant personnel heard a loud noise and felt severe vibrations in the turbine building and in the control room for approximately one to two minutes. Within the next minute, condenser vacuum decreased, turbine building roof vents opened, additional fire alarms activated, MSIVs closed, motor driven fire pump automatically started, GSW header pressure alarmed low, and a condensate demineralizer trouble annunciator alarmed.

1:18 p.m.: Residual Heat Removal (RHR) Division I service water was placed in the torus cooling mode to support reactor decay heat removal. The main condenser, the normal heat sink, was not available due to MSIV closure. Main lube oil pressure for the turbine read zero psig.

1:20 p.m.: an operator was dispatched to verify scram discharge volume integrity. To avoid the smoke/steam conditions in the turbine building, the operator left the control room through the relay room to get to the reactor building. The operator reported the scram discharge volume was intact.

1:27 p.m.: RHR Division II was placed in the torus cooling mode. The Reactor Core Isolation Cooling (RCIC) system was initiated to control reactor pressure.

1:30 p.m.: plant personnel donned SCBAs and entered the turbine building to inspect for fire. Heavy smoke and large amounts of flowing water were observed. One individual reported that there was no fire on the second floor of the turbine building. However, his communications were garbled and interpreted as indicating the presence of a fire.

1:50 p.m.: the operator attempted to open RCIC Valve E4150F011 to control the increase in the torus water level, but the valve tripped on overload and had to be opened manually (see Section 3.1 for a discussion of this issue).

1:51 p.m.: the Frenchtown Fire Department was called.

1:52 p.m.: an Unusual Event was declared based on a potential fire. The full fire brigade mustered and entered the turbine building. Fire was observed in the exciter brushes and some burning metal pieces were observed that had been expelled from the generator and exciter. The fires were extinguished using a portable CO2 extinguisher (brushes) and by kicking water on the burning metal pieces.

1:57 p.m.: an Alert was declared due to fire and fire potential in the turbine building.

2:15 p.m.: the Frenchtown Fire Department arrived on site with nine personnel and three trucks.

2:20 p.m.: operators began isolating GSW and the fire suppression systems to curtail the large influx of water into the turbine building

3:16 p.m.: approximately two hours after the start of the event, the Technical Support Center was considered functional.

3:53 p.m.: the circulating water pumps were shutdown because of increasing hotwell water level through damaged condenser tubes.

December 26, 1993

5:20 a.m.: the "B" Recirculation Pump Discharge Valve, B3105F031B would not fully close while attempting to place Division II of RHR in the shutdown cooling mode (see Section 3.2 for a discussion of this issue).

10:51 p.m.: the plant entered cold shutdown.

2.2 Turbine and Main Generator System Assessment

2.2.1 Turbine System Assessment

The main turbine is a horizontal, multi-cylinder impulse reaction machine consisting of one high pressure and three low pressure sections arranged in tandem to drive a single generator. The turbine was manufactured by GEC Turbine Generators, Limited of England. Steam from the Nuclear Boiler System is admitted to the main turbine via stop, control and intercept valves. Steam exiting the high pressure turbine is directed to two reheater separator units. After exiting the reheater separator units the steam is admitted to the three low pressure turbines via six sets of stop and intercept valves. From the low pressure turbine the steam exhausts to the main condenser.

The AIT reviewed the operating plant status just prior to the event and conducted interviews with turbine and generator specialists. Turbine-generator manufacturer (GEC) representatives were interviewed.

The AIT determined that the mechanical overspeed trip mechanism had actuated; however, there was no supporting data to indicate an actual overspeed condition occurred. Parameters recorded on the plant process computer, and on an analog strip chart recorder, provided evidence that at the time of the event the turbine was operating at 1800 rpm; then reduced to zero rpm in approximately 4 minutes (normal coastdown is approximately 15 minutes without condenser vacuum). The manufacturer stated that the configuration of the overspeed trip mechanical mechanism resulted in actuation when subjected to high vibration. This was a well known phenomenon that has been reproduced by the turbine manufacturer in a test facility.

The AIT also reviewed turbine vibration data that had been recorded on an instrument recorder in the main control room just prior to the event's initiation. This data indicated a normal 4 mils of vibration. In addition, vibration data was recorded by a computer monitoring system that was activated either by a turbine trip or high vibration. The AIT reviewed the data obtained by this system approximately one second after the turbine tripped. The data showed 50 mil vibration on several of the turbine bearings. The AIT concluded that available turbine vibration data indicated that there were no apparent precursors to the event available to the control room operators.

Due to the hydrogen burn associated with the event, the Generator Hydrogen Cooling System was reviewed. This system was operated on a charge/then isolate mode of operation, which limited the amount of hydrogen available for combustion in the event of a rupture. The rate of hydrogen usage by the system was also reviewed from the time of the event to several months preceding and no significant changes in consumption were noted. Loss of system hydrogen was attributable to several causes including entrainment in the seal oil system. While hydrogen consumption at Fermi 2 appeared to be higher than other turbine manufacturers' units of similar size, the team did not consider the hydrogen consumption rate to be significant.

The AIT reviewed Fermi 2's response to NRC Information Notice 91-83, "Solenoid-Operated Valve Failures Resulted in Turbine Overspeed," that was issued following the Salem turbine generator failure in November 1991. The licensee's response, detailed in Deviation Event Report 92-0017, concluded that a Salem type event was not a credible failure mode for Fermi 2 for the following reasons:

- Significant design differences exist between the two units (English Electric vs. Westinghouse). The Fermi unit was not susceptible to common mode hydraulic fluid contamination.

- Fermi 2 did not bypass or defeat the overspeed protection.

- SOVs at Fermi were routinely tested.

- PMs on the main steam system's unitized control system actuators were adequate to detect foreign debris in the system.

- Failure of one unitized actuator would not remove overspeed protection.

2.2.2 Generator System Assessment

Fermi 2's electric power output was rated at 22 kV output voltage stepped up to 345 kV by two parallel transformers, one 710 MVA and the other 800 MVA. These transformers were connected to the Fermi 2 345 kV station. The Fermi 2 345 kV station was connected by two double circuit 345 kV lines to the Detroit Edison power grid.

During power plant operation and shutdown, the 4.16 kV ESF buses were powered from the 120 and 345 kV preferred power systems. Fermi did not have an auxiliary transformer connected to the main generator output; therefore, the ESF buses were not affected by a main generator trip.

The currently installed main generator and exciter at Fermi 2 were manufactured by English Electric (now GEC Alsthom) with the following specifications:

- The Main Generator was rated for 1350 MVA, 1800 RPM, 22 kV, and 60 HZ.

- The exciter was shaft powered rotary device rated at 3600 kVA, 1800 RPM, 500 Vac, 120 HZ, that supplied a rectifier bank with 570 Vdc for the main generator field.

The generator casing and the end shields were of gas tight construction, supporting and enclosing the stationary windings, the core, and the gas coolers. The principal cooling medium was hydrogen gas contained within the casing. A separate cooling water system was provided for the stator windings. To prevent the escape of hydrogen from the generator casing along the rotor shaft, a shaft seal was provided at each end of the generator by the hydrogen seal oil system.

The generator was protected from faults and abnormal conditions by protective relay systems such as differential current, overcurrent, ground detection, loss of field, reverse power and directional overcurrent. The relays and the associated equipment trips were reviewed by the team. The plant scram sequence of events recorder indicated that the generator was isolated from the grid by the generator differential relays tripping the main generator breakers. The loss of field relay target indicated that the relay had also actuated during the event.

2.3 Precursor Events

2.3.1 Industry Events

The AIT reviewed potential industry events pertinent to the Fermi 2 turbine generator failure. The following turbine failure events were identified:

A. Susquehanna 1 - July 12, 1993

High cycle fatigue failure of two blades in a LP turbine manufactured by GE caused the blades to separate from the rotor. This mass loss caused high vibration which resulted in an automatic turbine/reactor trip. The failed blades caused damage to other blades and stationary rotors. In addition, 50 to 100 condenser tubes were damaged by blade fragments. No other damage resulted. The failures were attributed to torsional vibration from disturbances in the electrical system (high cycle fatigue). Subsequent inspections found cracks at the roots of several blades in another row of the same LP turbine. To prevent further failures, the turbine rotor was modified to change the natural torsional frequency.

B. Narora 2 (India) - March 30, 1993

Turbine blade fatigue failure resulted in high vibrations with subsequent breaches of the hydrogen and turbine lubricating oil systems causing hydrogen explosions and oil fires. Subsequently, Indian regulatory authorities required all other Indian reactors to shutdown and perform turbine inspections. These inspections identified additional unacceptable blade indications.

C. Salem 2 - November 9, 1991

Turbine overspeed caused blade loss in a LP turbine manufactured by Westinghouse. The excessive vibration from overspeed and mass loss breached the hydrogen and oil systems. Missiles penetrated the turbine casing. There was a hydrogen explosion and hydrogen and oil fires. The main condenser was damaged by turbine missiles.

D. Vandellos I (Spain) - October 19, 1989

Failure of 36 consecutive blades in a high pressure turbine manufactured by Alsthom - France resulted in high vibration, reactor trip, and hydrogen and turbine lubrication system breaches. Fires and explosions resulted. Fire damaged the seawater intake piping resulting in the release of approximately 650,000 gallons of seawater that caused plant flooding. There was extensive equipment damage from fires in the turbine and auxiliary reactor building. Failure was due to stress corrosion cracking with contributing factors being operation with wet steam and inadequate NDE.

Additional plant flooding was caused by 350,000 gallons of fire fighting water. The plant was decommissioned following the event due to the extensive damage from fires in the turbine building and flooding of the auxiliary/reactor building.

E. North Anna 1 - August 7, 1986

A piece of last stage blade broke off a LP turbine manufactured by Westinghouse. Blade failure was caused by high stresses induced by harmonic vibration due to turbine operation at low load with high condenser backpressure. Rotors in the LP turbine were replaced and procedural guidelines were established to prevent operation at low load with high condenser backpressure. There was no consequential damage.

F. Manshaan (Taiwan) - 1985

High cycle fatigue failure of eight blades in a LP turbine manufactured by GE. The blades separating from the rotor resulted in dynamic unbalance. High vibrations caused breaches of the hydrogen and lubrication systems and resulted in failure of the alternator shaft and a fire in the area of the alternator-generator. The blade failures were attributed to torsional vibration caused by electrical disturbances which excited a torsional mode of rotor vibration at or near its resonant frequency.

G. Yankee Rowe - February 1980

Failure of first stage disks in a LP turbine manufactured by Westinghouse. The disks were broken into large fragments and major damage was observed to several rows of blades and stators. However, no missiles penetrated the turbine casing. Cracks were found in the turbine casing. The licensee had not conducted NDE on the turbine since it began operating (approximately 20 years).

H. Aberthal (England - non-nuclear) - 1970's

Blade failures occurred due to water ingress into a LP turbine manufactured by GEC. Imbalance caused a breach of the hydrogen and oil systems resulting in explosions and fires.

I. Hinkley Point A (England - nuclear) - September 1969

Failure of disk (followed by hydrogen and oil fires) in a LP turbine manufactured by GEC. The failure was due to poor fracture toughness and stress corrosion cracking at disk keyway. Failure occurred while overspeeding the turbine during an overspeed test. Large fragments of LP disks became missiles; none struck the reactor.

J. Shippingport - February 1974

Low pressure disk failure in Westinghouse turbine while turbine was operating at full load. Blades and other missiles were found in the main condenser. No missiles penetrated the turbine casing. Gross movement of the turbine was apparent with casing bolts, valves and handwheels found in the turbine's vicinity. The initial failure was believed to be disk cracking that was followed by an explosion at the generator.

2.3.2 Fermi Precursor Events

A. September 1989 (First Refueling Outage - RF01)

1. Mass loss: Failed blades were found in the 5th stage of LP2. Subsequent inspection of LP1 and LP3 also identified damaged 5th stage blades. The failures were believed to be caused by turbine wheel resonance and water accumulation. The licensee thought that the mass loss resulting from the blade failures was the reason for the turbine balance and vibration problems experienced since 1988. The initial corrective action to resolve this issue was to remove the fifth stage blades of all three LP turbines.

2. Tip Rock: The eighth stage of each of the 3 LP turbines sustained excessive wear of lacing rods and lacing holes in the blades due to a phenomena called tip rock. This was attributed to operation of the turbine for long periods on the turning gear. To prevent future tip rock, "ripple springs" were installed under all the LP turbines' eighth stage blades. Due to the unavailability of replacement blades, the eighth stage blades were replaced only on the LP1 turbine. Blades removed from LP1 were refurbished and were to be installed in LP2 during RF02. Blades removed from LP2 during RF02 were to be refurbished and installed in LP3 during RF03.

B. December 1990

In December 1990, five blades in stage 4 of LP3 experienced fatigue failures with adjacent shroud damage. The failures were attributed to the high loading that stage 4 experienced since stage 5 had been removed in September 1989. Stage 4 blades that had failed were removed. Root blocks were installed and pressure plates were fitted.

C. April 1991 (Second Refueling Outage - RF02)

The licensee replaced stage 4 blades on all three LP turbines with blades of the original design having "understraps" to provide continuous shroud interconnection. In addition, the licensee replaced stage 5 blades on all three LP turbines with stiffer blades which also had "understraps." Drains were cleaned to eliminate water induction, and the turbine casing horizontal joints were repaired to reduce leakage. Refurbished stage 8 blades were installed in LP2. The stage 8 blades that were removed from LP2 were sent to a vendor to be refurbished.

D. September 1992 (Third Refueling Outage - RF03)

During RF03, the licensee did not replace the blades in stage 8 of LP3 as recommended by GEC. The agreement between Detroit Edison (DE) and GEC during RF02 was that the 8th stage blades of LP3 were to be replaced with the refurbished 8th stage blades removed from LP2. When GEC learned that DE was not going to replace those blades during RF03, GEC informed DE that if the stage 8 blades of LP3 were not replaced, a limited inspection should be performed during RF03.

The results of the inspection of the 8th stage blades of LP3 during RF02 indicated that Blade # 27 (North) had the most significant lacing hole wear. The GEC representative had noted on the data sheet that the results were "Accepted on basis that blades will be changed at RF03."

The results of the limited inspection that was done in RF03 did not quantify lacing hole wear of blade # 27 (or any other hole). The report had a blanket note that stated "This wear is of the same magnitude as that noticed in RF02 and it is not necessary to record this wear since all blades will be changed in RF04."

2.3.3 Assessment

The licensee's turbine personnel and onsite GEC personnel were very knowledgeable about the operating experience with turbines similar to the one at Fermi 2 (i.e. Kori 1, 2, 3, 4 and San Onofre 2, 3). However, knowledge about the failures and operating experience that had occurred with other manufacturers' units was very limited. There did not appear to be much concern, the thought being that Fermi 2 turbine was a good robust machine that had good operating history.

In retrospect, turbine operating experience at Fermi 2 was not very favorable (see Appendix B for precursor summary). For example, blade failures (referred to by the licensee as "mass loss") began as early as 1988 but were not discovered until September 1989 during RF01. During that time period, the turbine experienced repetitive vibration problems. The licensee, as shown in section 2.3.2, made numerous repairs and inspections of the LP turbines but was not fully successful in eliminating the vibration problems. The licensee retained and upgraded startup testing vibration monitoring instrumentation to help improve vibrational analysis. The licensee's inability to maintain their turbine vibration consistently at acceptable levels resulted in their decision to disconnect the automatic high vibration trip in 1989. Subsequently, the licensee has been moderately successful in reducing turbine vibration to the 4-6 mil range.

Detroit Edison's decision not to change the damaged LP3 stage 8 blades during RF03 as recommended by the turbine manufacturer, appears to be a possible causal factor of the December 25, 1993 event. The final determination of the nexus between delaying this activity and the failure of LP3 stage 8 will not be possible until metallurgical examinations of the turbine are completed.

2.4 Turbine Generated Missile Hazard Assessment

2.4.1 Regulatory Basis for the Safety Evaluation of Missile Hazards

General Design Criteria (GDC) 4, "Environmental and Dynamic Effects Design Bases," requires that structures, systems, and components important to safety shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures. Regulatory Guide (RG) 1.115, "Protection Against Low-Trajectory Turbine Missiles", recommends that the probability of safety systems being struck by a turbine missile be less than 1.0E-3 per year so that the hazard rate due to low trajectory turbine missiles be less than 1.0E-7 per year. This probability was a combination of; 1) a turbine missile generation probability, 2) the probability of the missile striking a safety system, and 3) the struck safety system fails to function. RG 1.115 recommends that the turbine missile analysis should include studies on potential missile trajectories and barrier designs with dimensions that should be thick enough to protect safety-related systems from turbine missiles.

The Fermi Unit 2 turbine regulatory basis was based on the staff's review of the licensee's turbine missile analysis as discussed in Section 10.2.3 of Fermi 2 Updated Final Safety Analysis Report. In NUREG-0798, "Safety Evaluation Report (SER) related to the Operation of Enrico Fermi Atomic Power Plant, Unit 2," the staff determined that there were no turbine generated missiles that would result in unacceptable radiological release or prevent safe plant shutdown. The staff concluded that the overall probability for turbine missile damage leading to consequences in excess of exposure guidelines was acceptably low and therefore safety-related structures, systems, and components were adequately protected from turbine missiles.

2.4.2 Turbine Missile Hazard Analysis

The purpose of the turbine missile hazard analysis was to analyze the potential turbine failure in order to determine the impact on safety-related systems and structures and to ensure adequacy of the shield barriers that protect systems from turbine missiles. The licensee's analysis was based on General Electric (GE) topical report 67SL211 that calculated energy losses in penetrating the turbine casing and the maximum energy of the missile fragment, and Sargent & Lundy Report SL-3075, "Protection Against Turbine Missile - RHR Complex."

A segment of the largest turbine disc weighing 8650 pounds, with a contact area of 10.4 square feet, and having an initial velocity of 304 miles per hour was selected as the design basis turbine missile to be considered in impact analyses. Four missile trajectories were analyzed for missile travel to the reactor, turbine, and auxiliary buildings and spent fuel pool. The control room and battery room in the auxiliary building were protected from a low trajectory missile by the combined walls of the turbine and auxiliary buildings, which were 4.5 feet thick. The safety-related systems in the auxiliary and reactor buildings were protected from high trajectory missiles by a combined thickness of 5.5 feet of concrete wall. The analysis did show a high trajectory missile penetrating the reactor building roof and landing in the fuel storage pool. However, the licensee calculated that the probability of this occurrence was 1.0E-4 per year. The licensee's analysis showed that there were adequate barriers to protect safety-related systems from large turbine missiles.

Based on review of the licensee's analyses, the inspector confirmed that while the analyses did not specifically consider the blades as potential turbine missiles, the licensee's analyses did consider high energy missiles which were larger than the ones that were generated on December 25, 1993, and as such the missiles from the December 25, 1993 event were within the plant's licensing basis. The analyses were based on fragment size, perforation energy associated with the fragments, and the nature of the surrounding structure so that the last stage disc was considered as a potential missile that would contribute most significant impact to the safety-related systems and components.

2.4.3 Turbine Generator Inspection/Surveillance Testing

The inspectors reviewed information concerning inspections and surveillance testing that were periodically performed on the turbine-generator. The information reviewed included a schedule of approximately 200 items that were agreed upon by DECo, the turbine-generator manufacturer and the insurance underwriter.

A review of the records of critical turbine inspections/overhauls and NDE performed at Fermi 2 indicated that these activities were carried out on a schedule that had been agreed to by the aforementioned groups. Table I contains a listing of the major inspections that were performed during the first three refueling outages.

Review of the turbine-generator inspection reports for RF01 and RF02 indicated that DECo managed work activities that were performed by GEC and other subcontractors such as W and GE performed specialized testing such as NDE and turbine balancing. The use of specialized external contractors to perform critical turbine-generator inspections and tests was a commonly accepted practice.

TABLE I

September 1989 (RF01)	HP Turbine LP 2 Generator Rotor Exciter
December 1990 (LP3 Stage 4 Failure)	LP 3
April 1991 (RF02)	LP 1
September 1992 (RF03)	Exciter: Inspection & Clean

2.4.4 Damage Assessment

At the time of the AIT exit, the licensee had not removed the turbine casing; therefore, the full extent of damage to the HP and LP turbines was not evident. However, general observations revealed an elliptical perforation about 1 foot by 3 feet on the portion of the LP3 turbine casing that surrounds the turbine side Stage 8 wheel. At least 4 blades had broken off from the wheel. Some of the blade fragments fell into the condenser and severed condenser tubes; one blade fragment penetrated the turbine casing, hit a concrete ceiling above a Moisture Separator Reheater and landed on a catwalk. None of the fragments penetrated the turbine building. The fragments and turbine internal components have not been metallurgically examined; therefore, the blade failure mechanism has not been determined. The staff will review the licensee's root cause analysis regarding blade failure when completed.

2.4.5 Assessment

The AIT determined that the discs in HP and LP turbines meet the acceptable design basis in the Fermi 2 Updated Final Safety Analysis Report because the discs did not fail during the event. The trajectory of the blade fragment was within those considered in the design basis. The missile fragment did not strike any safety-related system. The ability for the plant to shutdown safely was not compromised.

3.0 EQUIPMENT MALFUNCTIONS

While placing the reactor plant in a safe condition, three motor operated valves malfunctioned. The malfunctions were not caused by and did not contribute to the event.

3.1 RCIC Test Return Line Valve E4150F011 Failure to Open

At 1:50 p.m., on December 25, 1993, valve E4150F011 failed to open to allow the use of the RCIC turbine to control reactor pressure. The licensee had previously determined that because of static pressure on the valve disk the installed valve operator was not capable of opening the valve without first venting the upstream piping. As an interim measure, procedure SOP 23.206 had been changed to require venting the system prior to energizing the valve. However, the operator failed to vent the upstream piping as required. As a result, the valve failed to open. Plant personnel subsequently vented the line and manually opened the valve. Alternate methods were available for controlling vessel pressure and level if the operators could not have opened valve E4150F011. The valve operator was scheduled for replacement during the next outage. At that time a larger valve operator was to be installed. This issue is further discussed in Section 4.1 of this report.

3.2 Recirculation Pump Discharge Valve B3105F031B Failure to Close

On December 26, 1993, at 5:20 a.m., while placing RHR Division II into service for SDC mode of operation, the "B" recirculation pump loop discharge valve, B3105F031B failed to close. The licensee closed the RHR cross connect valve between Division I and II of RHR and failed the "A" side of LPCI LOOP Select logic. This prevented LPCI from transferring the injection path to the "B" recirculation loop in case the "A" recirculation loop developed a large leak. The licensee secured placing RHR Division II in SDC and placed Division I in SDC.

The licensee's failure investigation will be documented in an LER. Valve B3105F031B functioned properly when last called upon to operate in September 1993 during a forced outage. After the failure, electrical tests of the circuits available from outside containment indicated that the torque switch circuits for both the open and the close direction were open, thereby preventing operation in either direction. On December 25, 1993, the containment was opened and the switch case was removed from the operator. Three of the four wires between the limit switch and the torque switch were broken at the limit switch. The root cause of the broken wires was being investigated by the licensee's metallographic laboratory. The circumstances, location and nature of the wire breakage while inside the operator switch case suggest the failure mechanism to be associated with the vibration of the wire bundle. The proximity to the recirculation pump provides a viable source of vibration. INPO 83-037, dated October 1983, identified flow-induced and motor -induced vibration in piping systems and components as a cause for loosening of mechanical parts and broken wires. Any vibration of switches would be transferred to the wire bundle through the electrical lugs that were the sole support of the wire bundle. Tentative results of the licensee's investigation indicate that the direction of wire motion was in the plane of the flat portion of the lugs.

The licensee intends to replace all wiring in the A loop suction and discharge valves. Other replacements or modifications will be as considered based on the results of inspections of additional valves. The new wiring will be modified to utilize the information derived from their investigation to improve reliability of the bundle. This includes the use of 19 rather than 7 strand #12 wire, and the rerouting of wire to reduce wire vibration. Additional actions concerning resolution of this problem were anticipated as a result of the licensee's investigation and will be followed by the NRC in future inspections.

3.3 RHR Warm Up Valve E1105F611B Failure to Close

Valve E1105F611B failed to close when the plant was being placed in the RHR shutdown cooling (SDC) mode on the day after the accident. The contactor failed to energize the MOV twice, then closed the valve on the third attempt. This valve was used to warm up the RHR system prior to placing the system in SDC.

The licensee identified the contactor as the component that failed. The contactor was replaced on January 7, 1994. Tentative causes appeared to include the use of a Cramolin Cleaner (R-5) solvent or the failure to completely engage a spring catch on the contact cover after maintenance activities. As interim corrective actions, the licensee has discontinued use of the cleaner, and has implemented a program to remove any cleaner found on contactors and ensure full engagement of spring catches. The problem with contactors for MOVs had been identified as a generic problem that had caused other MOV failures at this plant and was already being investigated at the time of the failure. Preliminary investigation of the defective contactor confirmed the presence of excessive amounts of Cramolin (the oily solvent was dripping from the contactor). The results of this investigation will be reviewed by the NRC during future inspections.

4.0 OPERATOR AND NUCLEAR PLANT SYSTEM PERFORMANCE

4.1 Operator Performance Assessment

Overall, the control room operators' initial response to the event was effective in stabilizing the reactor plant and bringing it to a safe shutdown condition. However, subsequent actions failed to identify and address increasing main condenser hotwell level and decreasing CST level in a reasonable length of time. Not promptly addressing these indications resulted in a large amount of high conductivity water being pumped to the RPV. Although not detrimental to plant operation, delays in placing RCIC in a pressure control mode were a result of operators failing to follow procedures. The control room staff performed as a team, and generally took appropriate action commensurate with indications and procedures throughout the event. Control room staffing exceeded minimum Technical Specifications and was adequate to bring the unit to a stable, shutdown condition.

The event initiated a trip of the main turbine followed by a scram with main steam line isolation valve (MSIV) closure. One nuclear shift operator (NSO) initially addressed immediate actions for a scram while the other NSO actuated safety relief valves (SRVs) to control reactor pressure. The nuclear assistant shift supervisor (NASS) correctly implemented the EOPs, re-entering on subsequent entry conditions and transitioning to the plant general operating procedures to eventually achieve a safe shutdown condition. The nuclear shift supervisor (NSS) assumed the role of emergency director, verified notifications of offsite personnel and administered the emergency plan. Interviews with control room operators indicated communications within the control room were concise and audible.

One NSO attempted to rapidly stop the main turbine generator (MTG) by opening the vacuum breakers while the MTG was in coastdown with vacuum approximately 7 to 10 psia. The NSO elected to use this method based on the ongoing vibration, pegged bearing vibration indication, numerous turbine alarms and zero MTLO pressure. This method was described and taught in licensed operator training as a means to rapidly decelerate the turbine to prevent damage to the bearings and shaft. The licensee's procedures do not contain similar direction related to this situation and this method was not recommended as a normal method of decelerating the main turbine because of the windage stress placed on the large eighth stage turbine blades. Discussions with DECO and GEC turbine engineers indicated the windage stress would not normally be sufficient to exceed the allowable blading design stress. As a result of the relatively low vacuum and low speed of the turbine when the vacuum breakers were opened, there would not appear to be any significant stress placed on the last stage turbine blades.

The crew was slow to recognize the significance of high hotwell level indications and take action to stop feeding high conductivity water to the reactor pressure vessel (RPV). Circulating water (CW) inleakage was filling the main condenser hotwell via broken main condenser tubes. The condensate system was rejecting water to the condensate storage tank (CST). RCIC and SBFW were taking suction on the CST and maintaining RPV water level. At approximately 1:30 p.m., a control room operator observed annunciator 4D131, SOUTH HOTWELL LEVEL HIGH/LOW, associated high hotwell level indication, and high CST level indication, and informed the NASS. The NASS noted the alarm and indications, but his attention was diverted by concerns of placing the reactor plant in a safe condition, safety of plant personnel investigating the situation on the turbine floor, and coordinating action to isolate water and electrical systems without jeopardizing current plant conditions. Approximately 2 1/2 - 3 hours after event initiation, the NASS and his relief identified the problem and took action to isolate CW inleakage. The consequences of this delay appear to be long term and did not degrade reactor plant safety during the event.

Approximately a half hour after the turbine event, the operators attempted to place RCIC in the CST to CST mode for RPV pressure control as directed by the EOP for RPV Control (Reactor Control/Pressure). The EOP directs the operator to place RCIC in pressure control mode in accordance with SOP 23.206. Valve E4150-F011, RCIC Pump Test Return Line to CST, initially failed to open. The operators subsequently vented the associated line as required by SOP 23.206 and manually opened the valve.

4.2 Nuclear Plant System Performance Assessment

The AIT reviewed nuclear plant and safety-related system performance during the turbine generator failure and reactor scram event. The review included sequence of events recorder log (SOER), control room recorder traces, General Electric Transient Analysis Report System traces (GETARS), logs and interviews with operators who were on-shift during the event.

The reactor scrammed as designed per reactor protection system (RPS) signals. A turbine trip signal, with reactor power greater than 30%, caused the reactor to scram. Both RPS trip systems initiated trip signals which deenergized both associated scram pilot solenoid valves for each of the HCUs and the scram discharge volume vent and drain valves and allowed all 185 control rods to fully insert.

Other RPS signals received and processed included: turbine trip signal due to three of four turbine stop valves (TSVs) less than 5% closed (indication of closed), MSIVs greater than 8% closed (indicates closure), reactor water level (3) less than 173 inches (above TAF) due to shrink after the reactor trip. No safety injection signals were present. EDGs were not required to start since electrical power was always available to all four 4160 Volt ESF busses.

Condenser vacuum was lost due to the turbine blade penetration of LP #3 hood and other associated damage. MSIVs isolated due to low condenser vacuum at approximately 6.85 psia. One SBFW pump was manually started with suction from the CST after the reactor scram. Both divisions of RHR were aligned in torus cooling mode to remove decay heat being discharged to the torus via the SRVs. RCIC was manually initiated to assist with pressure control and to minimize SRV cycling.

Emergency core cooling systems were not required to function during this event but were available in standby mode. The unit was successfully cooled down to condition 3 (Hot Shutdown) and then to condition 4 (Cold Shutdown). Initial attempts to place RHR Division II in SDC were not successful because the "B" RRP discharge valve could not be closed. As a result, RHR Division I was placed in SDC.

The AIT concluded that the nuclear plant performed as designed and expected in response to the event.

4.3 Emergency Operating Procedure (EOP) Assessment

Performance and actions taken by the control room operators following initiation of the event were reasonable and effective considering the circumstances. Emergency Operating Procedures (EOPs) for Reactor Pressure Vessel (RPV) Control and Primary Containment Control were correctly followed and implemented. The crew successfully stabilized and brought the reactor to a safe shutdown condition.

Immediately following the event initiation, a reactor scram with main steam line isolation valve (MSIV) closure caused reactor pressure to increase and actuate SRVs resulting in increasing torus temperature and increasing torus level. Primary Containment Control (EOP) was entered after torus water temperature reached 95 #F and torus water level increased to greater than +2 inches. In anticipation of increasing torus temperature, the CRNSO placed both Division I and II RHR systems in torus cooling mode prior to reaching the entry conditions.

RPV Control was entered and re-entered several times after reactor water level decreased to less than 173 inches as a result of SRV pressure control causing shrink and swell. As required, immediate actions for reactor scram were verified per scram procedure 20.000.21. Power (RC/Q), Level (RC/L) and Pressure (RC/P) Control sections of the EOPs were concurrently executed. RC/Q was exited and subsequent steps of scram procedure 20.000.21 executed after verifying all rods inserted to position 00. RC/L was exited and cold shutdown procedure 20.000.04 executed after RPV level was restored using RCIC and SBFW to maintain reactor water level greater than 173 inches (Level 3). RC/P was exited and cold shutdown procedure 20.000.04 executed after using SRVs and RCIC to stabilize reactor pressure less than 1093 psig.

Overall, the EOPs provided sufficient guidance for the operators to stabilize the reactor plant and effect a safe shutdown condition.

4.4 Emergency Classification, Notification, and Event Reporting Assessment

At 1:15 p.m., the control room staff received indication of a seismic event followed by a turbine trip, reactor scram, and MSIV closure. A member of the control room staff contacted the staff at the Davis Besse plant who verified that no earthquake had occurred. The NSS and control room staff concentrated on securing the reactor and reacted to reports of fire in the turbine building. For personnel safety, the NASS made an evacuation announcement for the turbine building. Under direction from the control room, operators and fire brigade members searched the Turbine Building for indications of damage and fire, respectively.

At 1:51 p.m., the Frenchtown Fire Department (FFD) was called to provide additional resources to extinguish the fire. From interviews with plant personnel, the AIT learned that some confusion was noted in obtaining the correct telephone number for the FFD, which was finally resolved by the OSC coordinator. In addition, the FFD was not told that an ALERT had been declared at the Fermi site.

At 1:52 p.m., the NSS declared an UE based on RERP procedure EP-101, Tab 8, EP-102, "Fire in the plant or outbuildings containing equipment that requires offsite support." The UE declaration was late, in that at 1:15 p.m. the control room had indications of abnormal and extreme turbine vibrations and a reactor scram. However, the appropriate UE under tab 8, EP-102, "Control Room instrumentation indicates turbine rotating component failure resulting in a reactor scram" was not declared. The lack of timeliness of the classification did not appear to impact accident mitigation.

With the UE declaration, the NSS assumed the role of Emergency Director (ED). Minutes later, the ED received reports of a fire in the main lube oil reservoir area. Not knowing the extent of the fire, the ED conservatively declared an Alert at 1:57 p.m. in accordance with EP-101, Tab 8, EP-103, "Fire within the plant with potential to affect Nuclear Safety Systems or Engineered Safety Features." The emergency call out system was activated to augment the Emergency Response Facilities (ERFs).

Notification of the UE was appropriately suspended to provide the offsite authorities with the notification of the higher, Alert declaration. The Alert notification was made within the designated times, and the UE notification followed, indicating that the plant had escalated through it to the Alert. Follow-up notifications were made within the times required by licensee procedures.

Although the ED had the immediate responsibility of activating the accountability and assembly of onsite personnel, the ED did not activate these activities until 2:27 p.m., approximately 30 minutes after the Alert declaration. The ED appeared to be overly burdened in ensuring the fire brigade's augmentation and progress. Additionally, it did not appear that the ED followed the "Alert-Checklist for Immediate Actions," Attachment 1 of EP-103. The assembly of personnel was successfully completed at 2:47 p.m., within the licensee's goal.

The TSC and OSC/Alternate OSC were activated by incoming licensee personnel. The TSC and OSC were operational at approximately 3:16 p.m. and 3:19 p.m., respectively. Considering the holiday and number of personnel away from the facility, the augmentation of these facilities was very good. Although a few ERO positions were not immediately filled, personnel made adjustments to ensure that present, qualified ERO members filled those positions. Some delay in augmentation of the OSC was due to the evacuation of the Turbine Building and the necessity to activate the Alternate OSC. Interviews with selected OSC personnel and the OSC coordinator indicated that control of OSC activities was not very coordinated, but accident mitigation was not adversely affected. The emergency response organization appeared to aggressively react to the degrading plant conditions and the ingress of hundreds of thousands of gallons of water from the event.

At 3:16 p.m., the TSC was declared functional, and the responsibilities of ED were passed to the plant manager. The Alert was appropriately de-escalated to an UE at 5:22 p.m. The UE was properly terminated at 8:52 p.m. with the reactor in a safe and stable condition.

4.5 Fire Protection System Assessment

Overall, fire protection system performance during the Fermi turbine and generator fire was good. The automatic suppression and fire alarm systems operated as designed with all fires associated with the event contained and extinguished. The following is a sequence of events:

- At 1:15:47 p.m., a loud noise followed by approximately 2 minutes of strong vibrations was observed by plant personnel. A large number of alarms annunciated in the control room including high vibration indications on all turbine bearings, and alarms associated with turbine and reactor trips.

- At 1:15:59 p.m., two fire protection system alarms annunciated in the control room associated with the actuation of the turbine building wet pipe sprinkler and deluge suppression systems. The wet pipe sprinkler system provides fire protection for the turbine building second floor directly below the generator and exciter including all turbine bearing boats. The deluge suppression system protects the Hydrogen Seal Oil tanks and pumps.

- At some point between 1:15 p.m. and 1:51 p.m., the Shift Supervisor requested that the fire brigade assemble and respond to the event (the exact time could not be determined). Fire brigade members were in various areas of the plant at the initiation of the event. Operating personnel assigned to the fire brigade entered the turbine building and the reactor building to investigate and assess damage. In addition, one member of the fire brigade was sent into the turbine building to determine fire conditions. Due to background noises and the operator speaking through a SCBA, control room personnel thought the brigade member was reporting a fire on the turbine building second floor. Actually, the brigade member was stating that no fire was observed. The fire brigade leader then left the control room and entered the turbine building to investigate the fire conditions in the turbine building.

  Fire brigade members returning to the main fire brigade assembly point (third floor of the turbine building) were precluded from reaching the assembly point because smoke and steam had migrated from the turbine/generator area to outside the control room, tagging center and the fire brigade main assembly area. Pressure on the third floor of the turbine building resulting from the event prevented the tagging center door from opening. As a result of these conditions, some of the brigade members went to the alternate fire brigade assembly area and dressed out in protective clothing.

At 1:52 p.m., thirty-seven minutes after the event, the full brigade dressed out and responded to the turbine building fire alarms. The brigade used the Turbine Building Fire Protection Pre-Plan as a guide for building entry and fire fighting strategies. The plan was read by the NSS over the radio. This type of operation was not the normal way the brigade uses the fire protection pre-plan instructions.

The fire brigade arrived at the north end of the turbine building dressed in full turn-out gear and SCBAs. The brigade split into two crews and entered the turbine building second and third floors per the fire pre-plan. The brigade observed no fire on the second floor, but observed large amounts of water discharging down from the third floor. The third floor team observed a smoke and steam filled environment. Fire was observed in the exciter brushes and some burning metal pieces which had been expelled from the generator and exciter. The fires were extinguished using a portable CO2 extinguisher (brushes) and by kicking water on the burning metal pieces.

The brigade remained in the area until all fires had been extinguished and all other hazards associated with the fire had been eliminated.

- At 1:51 p.m., the Frenchtown Fire Department was contacted by the assistant shift supervisor and requested to respond to the event. The Frenchtown Fire Department arrived at approximately 2:15 p.m. The fire department members were staged outside the RA but did not enter at anytime.

- At 2:30 p.m., the fire brigade secured all previously activated sprinkler systems, but observed that the operation did little to eliminate water running down from the turbine building third floor.

- At 3:00 p.m., the fire brigade members returned to their normal duties.

The fire, smoke and steam generated by the event affected only the non-nuclear side of the plant. Reactor safe shutdown and safety related/safe shutdown equipment performance was not affected by the event. The turbine building is separated from all areas containing safe shutdown equipment by 3-hour fire rated barriers. The fire at the generator and exciter appeared to be the result of hydrogen leakage, explosion and burn. Hydrogen leakage appeared to have resulted from significant displacement of the turbine generator's shaft and internals causing the failure of the hydrogen seal oil system and generator hydrogen seals. The AIT identified no external combustible sources that contributed to the fire's cause.

As a result of the fire, the automatic wet pipe sprinkler system activated providing protection for the turbine generator bearing boats and turbine building second floor directly below the generator and exciter. The AIT determined, based on direct observation and interviews with fire brigade members, that the oil and hydrogen fires were rapidly extinguished and that no reflash occurred. Heat generated during the hydrogen explosion and burn, and steam released on the turbine building second floor, activated the hydrogen seal oil deluge system. There was no evidence of fire in that area.

Overall, Fermi 2 fire protection personnel and equipment performance was adequate. However, the AIT identified the following:

- The full fire brigade did not function as a team to respond to the turbine building to deal with the potential for existing fires until approximately thirty-seven minutes after the event. While, for this event, the thirty-seven minutes taken to respond did not result in a delay in suppressing the actual fires, a more timely brigade response could have more significant impact in dealing with future fires.

- Communications problems caused delays in assessing the fire's extent. These problems were attributable to the use of hand-held radios by personnel wearing SCBAs, water wetting communications equipment, and difficulties encountered using face mask microphones.

- There was no abnormal procedure for turbine building flooding. This delayed attempts to control flooding.

- Plant personnel experienced difficulty securing systems that were causing flooding. The difficulties could be traced to lack of instructions regarding equipment location and the lack of training for certain plant personnel in operating valves and electrical equipment.

- Plant personnel did not have in their possession a procedure for manually aligning the CO2 system to purge the generator. In addition, brigade members were unable to operate the CO2 system valves. This was due to either the water and oil on the valve handles or mechanical binding within the valves. At the AIT's completion, the exact cause of this problem had not been determined.

- Motion detectors worn by plant personnel during the response to the event (man down alarms) kept malfunctioning. This contributed to communications problems.

5.0 Offsite Radiological Consequences

5.1 Potential Gaseous Releases

The licensee evaluated the possible unmonitored release of gaseous radioactive effluents to the environment with the lifting of the turbine building smoke vents. These vents opened, as designed, as heat and pressure increased when steam was released from the damaged turbine. The turbine building heating, ventilation, and air conditioning (HVAC) system, the normal monitored release pathway for the turbine building, isolated when the turbine tripped. Other normal release paths were monitored by required radioactivity detectors; no abnormal releases were indicated by these monitors. The licensee based the preliminary unmonitored gaseous release evaluation on the following assumptions:

a. The MSIVs closed approximately one minute following the reactor scram and turbine building venting.

b. The December 16, 1993, isotopic results of the Steam Jet Air Ejector (SJAE) offgas were indicative of the concentration of noble gases in the steam.

c. The iodine activity in the steam per pound was equivalent to two percent of the iodine in the reactor coolant per pound. (Chapter 15.7.1 of the UFSAR contained this factor for an accident of similar release conditions.)

d. The reactor coolant's activity, at the time of the accident, was equivalent to the latest reactor coolant sample taken on December 22, 1993.

e. All the steam contained in the steam lines and turbine was released through the vents.

The licensee's evaluation was conservative in that it did not take credit for removal of steam through the vacuum of the condenser, the negative pressure from the radwaste building ventilation system, nor the adsorption of steam on the inner surfaces of the turbine building. Thus, the licensee's evaluation represented a maximum activity which could have been released via the turbine building smoke vents.

The NRC inspection team reviewed the licensee's evaluation and performed independent calculations using NRC computerized modeling programs, which showed good agreement with the licensee's calculations. The licensee calculated that approximately 2.8 millicuries (mCi) (103.6 megaBecquerels (MBq)) of iodine-131 and iodine-135, and 42.8 mCi (1584 MBq) of noble gases were potentially released. These values were a small fraction of the NRC effluent release limits and were comparable to the normal radioactive gaseous effluents for the week of December 21, 1993, (i.e., 0.62 mCi (23 MBq) of iodine-131 and iodine-135 and 2500 mCi (92,500 MBq) of noble gases.) The dose to the public from the postulated release would be less than 0.01 mrem (0.1 microSievert (uSv)) for a person located at the site boundary during the release, which presents no undue risk to the public.

5.2 Potential Liquid Release Pathway

During the event, approximately 500,000 gallons of lake quality water mixed with approximately 17,000 gallons of oil entered the third floor of the turbine building and, subsequently, flowed into the building basement, as described in Section 6.1. Approximately 3000 gallons of this water combined with approximately 15 gallons of oil were released through the ground level turbine building truck bay overhead door into the storm drain system. The storm drain system emptied into the site canal system which had a containment system to prevent oil from entering the lake. Water in the canal system emptied directly into Lake Erie.

The licensee sampled the water on December 25, 1993, as it escaped the turbine building and found no detectable radioactive contamination. Liquid samples from the storm drain system and the canal were obtained and analyzed by the licensee and NRC, as described in Section 5.3.1, and no detectable radioactive contamination was found.

The licensee also evaluated the potential release of radioactive liquids via backflow through the Circulating Water System (CWS) into the circulating water reservoir. Following the event, water from the General Service Water (GSW) system entered the condenser water boxes, leaked through CWS isolation valves, and emptied into the reservoir, which was periodically decanted to Lake Erie. Because the licensee found contamination in the water boxes, the licensee and NRC analyzed samples from the reservoir and verified that no contamination was detectable; reservoir samples were also obtained during water transfer from the radwaste building basement to the condenser hotwell, that verified no detectable contamination had been released from the hotwell. NRC sampling evaluations are further described in Section 5.3.1. The licensee continued to sample the reservoir weekly. Based on these measurements, the licensee and NRC concluded that no measurable radioactivity was released through this pathway.

No other effluent pathways were identified as having the potential for a significant release of radioactive material.

5.3 NRC Radiological Measurements

The NRC Region III mobile laboratory was dispatched to confirm the licensee's radioanalytical ability and to independently measure onsite and environmental samples. Results are described below and shown in Appendix F. Maps denoting sample site location are presented in Appendix G.

5.3.1 Environmental Monitoring

Lake Erie water and sediment samples were collected on January 5 and 6, 1994, placed without preservation into counting containers, and analyzed for environmental levels of radioactivity. The water samples were below minimum detectable activity (MDA) for the nuclides typically seen in plant effluents. The sediments contained only an extremely low level of cesium (Cs-137), probably from past national and international weapons testing fallout. These results were consistent with the licensee's data in the 1991 and 1992 Annual Radiological Environmental Monitoring Program (REMP) Reports. Two independent samples were also collected from the reservoir on January 6, 1994. The results were in agreement with the licensee's results taken from the reservoir on December 26, 28, and 31, 1993. The NRC data is presented in Appendix F.

Samples were also taken from the canal onsite, from the connection of the canal to Lake Erie, and from two REMP sites, DW-1 (Monroe Water Intake) and SW-3 (Fermi 2 General Service Water). NRC results (Appendix F) were below the MDA and were consistent with the licensee's data.

5.3.2 Onsite Monitoring

Four inplant liquid samples were collected by the licensee and analyzed by the licensee and by the NRC. The results of these analyses are contained in Appendix H and the criteria used for comparisons is contained in Appendix I.

The licensee's measurements were in excellent agreement with the NRC results. The licensee achieved 48 agreements out of 51 radioisotopic comparisons. The other three were below the licensee's MDA. The inspectors reviewed the licensee's MDAs; no problems were identified.

6.0 Water Management

The turbine/generator failure resulted in both missile and vibration damage to oil- and water-containing components and pipes. In addition, the fire protection system released water to the turbine building. Details of the water and oil release and the licensee's efforts in response to the release are given below.

6.1 Water Inventory Summary

Damage to the main condenser tubes resulted in lake water (from the CWS) entering the condenser hotwell and being pumped to the condensate storage tank (CST) as the hotwell filled. CST water was sent into the reactor vessel via SBFW to maintain vessel inventory. Approximately 500,000 gallons of water was released to the turbine building floors due to damage to: 1) a GSW pipe to the generator's hydrogen coolers; 2) fire protection system components; and 3) a turbine building closed cooling water system pipe. In addition, the rupture of a supply line from the generator lube oil tank resulted in the release of approximately 17,000 gallons of oil to the turbine building floors.

Much of the water and oil on the floors drained to turbine building sumps and then to the waste collector tank and floor drain collector tank in the basement of the radwaste building. These tanks overflowed (as designed) to the radwaste building floor drain and equipment drain sumps, which overflowed to the basement floor. Eventually, the basement was flooded to approximately six feet with a mixture of water and oil. Plant staff estimated the quantity at approximately 500,000 gallons. Although the water and oil originally spilled to the turbine building floors was not radioactively contaminated, the water became contaminated after mixing with the contents of the tanks and sumps in the radwaste building. In addition to the radwaste building basement, water and oil drained to several other locations in the turbine building without sump pumps and drained outdoors onto the ground by flowing under the closed turbine building truck bay doors.

With the plant's normal liquid radwaste processing equipment rendered inoperable by the flooding in the radwaste building basement, the licensee established a water management team to formulate plans for returning plant water inventories to acceptable quantity and quality levels. These plans centered on the use of portable water cleanup equipment. The NRC established an oversight team to review the licensee's actions and independently sample and analyze water and sediment. Results of various oversight team activities during the initial phases of the water cleanup process are discussed in Section 5.0 and below. Additional NRC oversight after the current inspection will continue and be reported in subsequent NRC inspection reports.

6.2 Water Recovery and ALARA

Plant management placed a high priority on returning water inventories to normal quantity and quality. Several temporary modifications were initiated to clean reactor and CST water and move water from the radwaste building basement to the condenser hotwell for eventual cleanup. Each of the modifications is discussed below.

- Temporary Modification No. 93-0012: This modification was designed to provide clean condensate return tank (CRT) water to the control rod drive (CRD) seal flushing/cooling water supply. Temporary connections were made between CRT and CRD components in the reactor building.

- Temporary Modification No. 93-0013: This modification was designed to provide a flow path from the reactor vessel, through the reactor water cleanup (RWCU) system and a temporary filter demineralizer, to the CRT via the high pressure cooling injection (HPCI) test line. The purpose of this modification was to provide a letdown flow path to maintain reactor vessel level while flushing control rod drive mechanisms. Modification components were located in the turbine building.

- Temporary Modification No. 93-0015: This modification was designed to clean reactor water with a temporary demineralizing system connected to the permanent RWCU system. This modification was necessary because the high level of radioactive and chemical contamination in the reactor water would require frequent changeout of RWCU demineralizer resins. This changeout was not possible because the flooding of the radwaste building basement rendered much of the required processing equipment inoperable. The temporary connecting pipes, hoses, and other components needed for the modification were installed on the permanent RWCU system located in the reactor building.

- CST Temporary Demineralizer and Discharge Line Installation: This modification was designed to install a temporary liquid effluent discharge line from the CST to the environment; a temporary demineralizer system to recirculate and treat the water prior to discharge; and a diked area to contain the system. At the completion of this inspection, this modification was still under development.

- Temporary Modification No. 94-0002: This modification was designed to transfer water from the radwaste and turbine buildings' basements to the condenser hotwell for subsequent transfer to the CST for cleanup and discharge. This modification also provided for the cleanup of standing oil in those areas.

For each of the modifications, the licensee performed safety evaluations and exposure control reviews. Radiation work permits (RWPs), work packages, and procedures were also written or revised as necessary. For many of these evolutions, there was department management involvement, quality assurance oversight, and onsite review organization (OSRO) approvals.

To ensure the modifications were implemented consistent with safety evaluations, ALARA reviews, and special procedures, and operated in a safe manner, NRC inspectors and supervisors interviewed cognizant plant and contractor staff and walked down the installed equipment before and during equipment operation.

Specifically regarding Temporary Modification No. 94-0002; the condenser hotwell was assessed to determine structural intregity as a result of the turbine event. The hotwell was routinely flooded up after each refueling outage to identify leakage in main condenser penetrations below elevation 599 feet. Procedure No. 23.107.02, "Floodup and Drain Down of Main Condenser System," Revision 7, was performed during the last outage with no significant problems. The location of the reactor feedpump turbine outlet duct at elevation 603 feet limited the height to which the hotwell could be flooded. Based on this, unless the hotwell was structurally damaged, there was no structural concern with flooding up the hotwell.

The main condenser was an independent structure isolated from the turbine above by a flexible connection and supported below by 12 concrete piers. The sides were unsupported and relatively free of penetrations. Damage to the hotwell could have been caused by turbine missiles from above or severe vibration from the turbine into the foundation and up into the condenser. The licensee performed a detailed walkdown of the hotwell and determined that there had not been any structural damage. An NRC regional inspector walked down portions of the hotwell structure to confirm this conclusion. Accessible portions of the hotwell sides were inspected and there were no indications of missile impingements on any of the surfaces. The baseplates and piers were also inspected and there was no evidence of any distortion or relative movements. Based on these observations, there did not appear to be any structural concerns regarding floodup of the hotwell.

As a result of these reviews, the AIT determined that the licensee was conservative in the development of the temporary modifications. Implementation of the modifications completed during this inspection were acceptable. Minor delays were experienced during installation of several modifications due to equipment problems with contractor-supplied components.

The inspectors also noted that careful consideration was given to and preventive measures were taken for reducing radiation exposure to workers for the two modifications (Nos. 93-0013 and 93-0015) with the potential for producing significant (greater than 2 person-rem (20 person-milliSieverts (mSv))) exposures. Proper evaluations were performed to ensure that worst case leaking hoses and equipment associated with any of the temporary modifications would have only minor dose consequences for station personnel. Radiation protection and ALARA staff were pro-active, their involvement in each of these evolutions was significant, and they appeared to be fully aware of and involved in all aspects of the water/oil recovery effort. In addition, the plant's excellent prior radiological controls performance, specifically its prior efforts to maintain a low percentage of the plant as contaminated, made this event less severe than it would have been had those controls not been in place.

6.3 Reactor Water Chemistry

The reactor water chemistry was adversely effected by the event as described in Section 6.1. Prior to December 25, 1993, the reactor chemistry parameters were excellent. Reactor water conductivity was approximately 0.08 micro-Siemen/centimeter (uS/cm) and the concentration of chlorides was less than 2 parts per billion. After the event, the conductivity increased to over 185 uS/cm and the chloride concentration exceeded 10 parts per million (ppm). These levels exceeded the TS required shutdown reactor chemistry of 10 uS/cm and 0.5 ppm for conductivity and chlorides, respectively.

The radioactive and chemical contamination cleanup from the demineralizers installed as part of Temporary Modification No. 93-0015 was very effective. For example, in the first 24-hour period of operation, the reactor water conductivity was reduced from 65 uS/cm to 35 uS/cm. Use of these demineralizers continued at the end of this inspection.

The effects of the poor water quality on reactor components and fuel have not been completely analyzed. The contaminants introduced a corrosive environment for reactor components. However, the licensee was proactive in reducing the temperature of the reactor coolant to reduce the effects of the corrosion. Preliminarily, the licensee did not expect any damage on reactor components, but the licensee had not completed a full evaluation of the effects of the evolution. This evaluation will be followed in future inspections by NRC Region III inspectors.

6.4 Postulated Radiological Consequences Assessment

The possible releases of radioactive material to the environment after the turbine/generator failure would have produced radiation levels at the site boundary that were a small fraction of the relevant NRC criteria and a small fraction of the doses postulated in the FSAR.

Precautions were being taken to preclude accidental releases. Nevertheless, various accident scenarios have been postulated and the consequences assessed. The NRC concluded that the potential accidents associated with the processing of the water from the turbine failure will not produce doses in excess of the relevant NRC criteria.

Doses associated with possible releases are discussed in the following sections.

6.4.1 Release from the Condensate Storage Tank (CST)

The CST contained an estimated 531,840 gallons of slightly contaminated water. The storage space was needed for more seriously contaminated water, such as that from the radwaste building basement, so consideration was being given to releasing the water from the CST to the environment. This would not be considered an accident so the criteria for the release of water during normal operations would apply.

Isotopic analysis performed by the licensee and independently verified by the NRC via a split sample determined the concentration of radioactivity in the CST water to be about 0.000033 microcuries per milliliter (1Ci/mL) (1.22 Bq/mL). The dose was dominated by two cesium nuclides (^{134}Cs and ^{137}Cs) which are present at a concentration of 0.000018 1Ci/mL (0.67 Bq/mL) dose-equivalent ^{137}Cs. To meet the NRC dose criterion, this concentration must be reduced by a factor of 18,000 before it reaches fish. For Fermi II, the lake provides dilution by a factor of 5 ("near field" dilution) so an additional factor of 3600 would be needed. This could be provided by demineralization, dilution, or some combination of the two. At a flow rate of 17,000 gallons per minute (gpm) (normal decant flow from the reservoir to the lake), this dilution could be achieved in 79 days.

Plans for release of the water from the CST to the lake were not complete at the end of the inspection but if the release were to take place, a more complete isotopic analysis would be necessary, especially to determine the concentrations of the beta emitting nuclides, e.g., tritium (^{3}H), iron-55 (^{55}Fe), and strontium-90 (^{90}Sr). Tentative plans called for the reduction of the Cs concentration with demineralizers, which can reduce concentrations by a factor of 100 or more.

Thus, following processing through demineralizers and sampling to ensure compliance with regulatory requirements, the water from the CST should be acceptable for release as a part of normal operations of the plant. The NRC will closely monitor the licensee's releases associated with this event, including taking independent samples and performing dose estimates prior to the releases. The results of these activities will be reported in future inspection reports.

6.4.2 Postulated Accidental Release of Water from the Radwaste Building Basement

The turbine/generator failure released a large quantity of water, which subsequently became contaminated, into the radwaste building basement. A postulated accident of this nature is addressed in the UFSAR, but the UFSAR accident scenario entailed the assumption of the failure of the building and the release of the activity to the ground water. The concentrations for the UFSAR accident, calculated in accordance with the NRC's Standard Review Plan, Section 15.7.3, were below the criterion by a factor of 319.

The top of the ground water table around the radwaste building was some 12 feet above the top of the water in the basement, so if the basement leaked, ground water would flow into the building. Furthermore, the licensee stated that the basement has been dry for an extended period of time. Thus, a major release of the water from the basement was not expected, but could occur as a result of another event such as an earthquake. Therefore, the consequences of such a release have been evaluated.

Because of the limited access to the flooded parts of the basement, there was considerable uncertainty in the amount of radioactivity in the basement. The water volume was estimated to be about 500,000 gallons. The radioactivity was measured in samples from one location in the basement and found to be about

0.0004 μCi/mL (14.8 Bq/mL). This was not a concentration that presented a serious hazard to people who work with it, but it was well above the NRC's permissible concentration for public exposure (10 CFR 20 Appendix B, Table II, Column 2), so precautions were being taken to avoid its release. The analysis did not determine the concentration of beta emitters so, for this analysis, the ^{3}H concentration was taken as equal to that in the reactor coolant and (in accordance with the Offsite Dose Calculation Manual) the total activity was increased by 10% to account for the possible contribution of other beta emitters such as ^{55}Fe and ^{90}Sr.

If the radwaste building basement were to fail, ground water would leak into the building until the water level inside became the same as that outside. To compensate for the uncertainty in our knowledge of the contents of the basement, this dilution was not taken into account in our analysis. Once the water level inside and outside the building became equal, there would be transfer of the contaminated water into the ground water. The contamination would then migrate to the lake. Hydrologic analyses reported in the UFSAR indicated that it would take about five years for the contamination to reach the lake. This time period would be sufficient for radiological decay to effectively eliminate the short-lived radionuclides such as iodine-131 (^{131}I) and chromium-51 (^{51}Cr). During this migration, the concentrations of the radionuclides would also be reduced by attachment of the radionuclides to the soil and by dilution by ground water but, as an added conservatism, this reduction has not been taken into account in this analysis. Even so, the calculated radionuclide concentration would be less than five times the NRC's permissible concentration for public exposure in drinking water (MPC) when the contaminated water reached the lake. The hydrological dispersion analysis reported in the UFSAR shows that there would be a dilution factor of at least 77 between the point at which the water would enter the lake and the nearest drinking water intake. Thus, at the drinking water intake, the concentration would be less than 7 percent of the MPC (10 CFR 20 Appendix B, Table II, Column 2).

Thus, the accidental release of the contaminated water in the radwaste building to the ground water would not exceed the NRC accident criteria.

6.4.3 Postulated Accidental Release from the Condenser

In order to regain use of the equipment in the radwaste building, the contaminated water was being transferred to the condenser hotwell for temporary storage. The transfer piping was entirely within the radwaste and turbine buildings so any spill in this process would be contained and would not result in radiation exposure offsite. Possible releases from the condenser could reach the environment and so must be considered. The following two scenarios were assessed: (1) small leaks to the condenser tubes, and (2) catastrophic failure of the condenser.

A small leak to a condenser tube would not be a direct release to the environment but could contaminate the circulating water and the reservoir. The reservoir was connected to the lake only by the decant (blowdown) system so releases to the lake could be controlled. Control of contamination in the reservoir would constitute an operational problem so provisions were included to detect and plug leaks before problems arose.

A catastrophic failure of the hot well was highly improbable, but could occur, possibly as a result of a seismic event. A release to the environment would not occur unless both the hotwell and the turbine building failed. If the contaminated water were released, it would enter the groundwater. From this point the sequence of events and the resulting concentrations would be essentially the same as those from the failure of the radwaste building as discussed in the preceding section.

Thus, the possible release of the contaminated water from the hotwell does not constitute a hazard to the public nor constitute an accident not encompassed by the accidents addressed in the UFSAR.

6.4.4 Postulated Spills at the Surface

In the cleanup of the Fermi 2 facility, it will be necessary to transfer and process substantial quantities of contaminated water. Radioactivity levels range from "undetectable" (less than about 0.0000001 µCi/mL (0.004 Bq/mL) to about 0.017 µCi/mL (630 Bq/mL) in the reactor coolant. Almost all this water was sufficiently contaminated to produce detectable levels of surface contamination if the water were spilled. Furthermore, spills would tend to increase the exposure of workers in the plant. Procedures developed for handling this contaminated water were reviewed by the NRC prior to use and included provisions for minimizing the likelihood of spills.

Special attention must be paid to possible spills that could release substantial quantities of contaminated water to the ground surface. Water spilled on the surface is a special concern because it could run to the lake without the extended time delay associated with the movement with ground water. Furthermore, the NRC criterion of complying with the off-site MPCs would be applied at the point where the contaminated water entered the lake (rather than at the drinking water intake). Since (1) most of the water was contaminated to levels above the off-site drinking water MPC values, and (2) there was little opportunity for dilution or for decontamination of uncontained spills, uncontained spills generally are unacceptable. Therefore, plans for moving, processing, or storing contaminated water should include provisions for containing any and all spills. These provisions may include keeping the operation inside existing buildings with established integrity, or building berms, dikes, or dams that will contain any substantial spill.

6.4.5 Conclusion

Based on the AIT's review of the licensee's "Temporary Modification Requests" and "Safety Analyses" as well as independent analyses of potential accidents, it was concluded that the contaminated water could be processed within regulatory limits and without introducing the possibility of an accident that either exceeds the NRC radiological criteria or is more severe than accidents addressed in the UFSAR.

7.0 LICENSEE EVENT ASSESSMENT EFFORTS

The licensee established 16 teams to assess the event. The AIT performed a more detailed review of two of these teams, the Scram Investigation Team (SIT) and the Turbine-Generator Assessment Team (TGAT).

7.1 Scram Investigation Team (SIT)

The SIT was tasked with identifying the initiating scram signal and assessing the overall plant response to the event. The team was headed by a senior manager at the station and included five additional members. These five individuals were selected from several departments included design engineering, safety engineering, system engineering, and licensing. The team also used additional personnel for specific tasks.

The team operated independently of station management, but kept management informed of its findings. The team managers maintained contact with the members of the AIT and provided information needed by the AIT. The SIT was well organized and managed. The six permanent members of the team, with additional temporary assistance by other plant personnel, as needed, had the required expertise to accomplish the team's objectives. The SIT findings will be documented in an LER.

7.2 Turbine-Generator Assessment Team (TGAT)

The TGAT was tasked with determining the root cause of the event and developing a plan for damage assessment, repair options, corrective actions to prevent recurrence, reassembly, and startup.

The team was headed by a senior manager at the plant and included more than 20 members. The team included representative from General Electric, GEC, Salem, and Fermi 2 staff in varied disciplines.

The team operated independently of station management, but kept the management informed of its findings. Station management provided support to the team, including furnishing all data and information required by the team. The team manager maintained communications and contact with the AIT and provided information needed by the AIT. The TGAT was well organized and managed. The team members had the required expertise to accomplish the team's objective. The team explored in a careful, methodical fashion all the possible root causes of the event.

7.3 Quality Assurance and Independent Safety Engineering Group

The inspectors interviewed quality assurance (QA) management to determine what quality department oversight functions would be performed during the turbine/generator event recovery process. As a result of the event, the QA department has refocused the audit program by scheduling audits specifically applicable to the evolutions required for the recovery. These audits include:

- Radiological effluents
- Radiological material transfer and disposal

- Safety reviews and evaluations
- Training and qualification of audit staff (contractor qualifications)
- Nuclear fuel management and SNM accountability (new core reload analysis)

The Nuclear Quality Assurance Group had been involved in the development of the recovery plans and will conduct surveillances of all major activities during the recovery process. Several teams had been established to cope with the specific concerns that have developed as a direct result of the event. These teams include, but were not limited to:

- System Layup Team
- System Walkdown Team
- Structural and Support System Team
- Scram Team
- RF 04 Outage Preparation Team
- Radwaste Restoration Team
- Reactor Vessel Internals Assessment Team
- Sequence of Events Investigation Team
- Nuclear Fuel Concerns Team

Of particular interest to the NRC were the nuclear fuel concerns and reactor internals assessment. Neither plan had been completed. However, a draft of the nuclear fuels concerns was reviewed. This document dealt primarily with the intrusion of impure water to the reactor vessel and the potential effects on the long term reliability of the fuel. Although not complete, definitive plans were in progress to assess this impact.

The inspector interviewed the supervisor of the Safety Engineering Group to determine the involvement of the Safety Engineering Group and the Independent Safety Engineering Group (ISEG) on the recovery from the event.

The ISEG on a daily basis maintained cognizance of plant conditions, configuration and activities by attending the Plan of the Day meeting, scheduling meetings, and by walking down the control room panels. ISEG confirmed both electrically and mechanically that required systems were, in fact, available. In addition, the Safety Engineering Group participated in the scram review and the turbine-generator assessment teams and reviewed all temporary modifications pertaining to water management activities.

8.0 PLANS AND SCHEDULES FOR REPAIR AND RESTORATION

The licensee originally planned to shut down in March 1994 for a refueling outage. The December 25, 1993 forced outage required rescheduling of the planned outage activities and the inclusion of the additional work required for the repair of the turbine, generator, and associated auxiliary facilities and equipment. The licensee developed a Fermi 2 Turbine-Generator Assessment Team Action Plan (TGATAP). The plan was reviewed by the AIT team and found to be adequate, thorough and flexible enough to accommodate changes as needed through the use of modular attachments.

The two primary concerns which prevailed throughout the TGATAP were the reduction of personnel hazards and preserving a record of the damage and recovery process. This ensured, during the cleanup and recovery process, that evidence important to the root cause analysis would be preserved.

The TGATAP described the team's organizational structure, the team's goals and objectives and included restrictions regarding how to conduct the initial damage assessment. These restrictions established access control, conduct of visual walkdowns, methods of documentation/description of loose pieces and assessment of external damage. Quality assurance verification has been included in the development and implementation of the Action Plan. Cleanup and preparation for internal main turbine-generator inspection were also covered.

The plan also addressed methods for conducting metallurgical reviews. When possible, parts will be photographed in place prior to removal. An initial condition assessment will then be performed using a low power loop, a wide field microscope or portable alloy analyzer. The inspection will evaluate material conditions for ductile or brittle fracture, high or low cycle fatigue or environmentally assisted cracking.

9.0 EXIT MEETING

The team met with licensee representatives (denoted in Appendix C) in a public exit meeting on January 19, 1994, and summarized the purpose, AIT Charter items, and findings of the inspection. The licensee did identify as proprietary some of the documents associated with the GEC turbine that were reviewed by the team.

APPENDIX A

Sequence of Events for Fermi Unit 2 Turbine/Generator Failure

December 25, 1993

Initial Plant Conditions:

- Operating at 93% power
- Reactor and balance of plant normal
- No abnormal alarms or indications on the turbine-generator

TIME	EVENT
1:15 p.m. (T = 0)	Turbine trip, reactor scram, seismic alarm, multiple turbine vibration alarms, fire alarm, bearing oil pressure low, turbine building HVAC tripped, loud noise and severe vibrations experienced by plant personnel.
1:16 p.m. (T = 1 min)	Closure of main steam isolation valves, additional fire alarms, turbine building roof vents opened, condenser vacuum decreasing, electric fire pump auto start, safety-relief valve manually opened, condensate demineralizer system trouble alarm, general service water (GSW) header pressure low.
1:17 p.m (T = 2 min)	Manually started Division I of Residual Heat Removal (RHR), service water, generator exciter field ground alarm, jacking oil pumps tripped, operator could not get jacking oil pumps running, main lube oil pressure 0 psig.
1:18 p.m. (T = 3 min)	Started Division I of RHR in torus cooling mode.
1:20 p.m. (T = 5 min)	Restarted turbine building HVAC to improve visibility in turbine building, shut down heater drain pumps, operator sent to reactor building to verify scram discharge volume integrity.
1:25 p.m. (T = 10 min)	Operator reports scram discharge volume intact, South Condenser Pump shut down.
1:27 p.m. (T = 12 min)	Started Division II of RHR service water and Division II of RHR in torus cooling mode.
1:29 p.m. (T = 14 min)	Reactor Core Isolation Cooling (RCIC) system initiated.
1:30 p.m. (T = 15 min)	Personnel entered turbine building to inspect for fire. Control room operators started standby feedwater.

APPENDIX A

Sequence of Events for Fermi Unit 2 Turbine/Generator Failure

December 25, 1993

(Continued)

1:31 p.m. (T = 16 min)	High Pressure Coolant Injection (HPCI) suction auto transfer.
1:40 p.m. (T = 25 min)	Personnel from operations, radiation protection, and emergency preparedness entered turbine building for inspection.
1:50 p.m. (T = 35 min)	HPCI valve motor overload, valve opened manually.
1:51 p.m. (T = 36 min)	Frenchtown Fire Department called.
1:52 p.m. (T = 37 min)	Unusual Event declared, fire brigade mustered and enters turbine building.
1:57 p.m. (T = 42 min)	Alert Declared.
2:11 p.m. (T = 56 min)	Hydrogen seal oil pump shutdown, isolated hydrogen to turbine building, began lining up carbon dioxide to generator.
2:20 p.m.	Began isolating GSW and fire protection headers in turbine building to stop influx of water.
3:16 p.m.	Technical Support Center functioning.
3:35 p.m.	Torus temperature high alarm, started control air compressors.
3:37 p.m.	Shutdown turbine building closed cooling water (TBCCW) pumps due to low water inventory.
3:40 p.m.	West Station Air Compressor tripped due to high temperatures.
3:41 p.m.	Noninterruptible air supply compressors started due to loss of station air.
3:48 p.m.	RCIC shut down.
3:53 p.m.	Circulating water pumps shutdown.
4:05 p.m.	Started RCIC suction to torus.

4:11 p.m.	Condensate system shutdown.
4:26 p.m.	Circulating water system isolated.
5:22 p.m.	Downgraded to Unusual Event.
8:52 p.m.	Unusual Event terminated.
December 26 5:20 a.m.	"B" Recirculation Pump Discharge Valve does not fully close when attempting to place Division II of shutdown cooling into service.
8:51 p.m.	Cold shutdown achieved.

PRECURSORS/POSSIBLE CAUSAL FACTORS

1986	Jan 1988	August 1988	March 1989		September 1989	December 1989		December 1990	April 1991	September 1992	December 1992	April 1993	May 1993	December 1993
Turbine was on turning gear for an extended period of time (15,000 hrs).		Automatic turbine trip on high vibration of #8 & #9 bearings. Licensee attributed vibration to an air line failure which caused excessive cooling of the turbine lube oil.	Automatic turbine trip on high vibration was removed.		Refueling outage. Discovered damage to Stage 8 blades in all LP turbines ("tip-rock"). Installed ripple springs on all Stage 8 blades, all LP turbines. Replaced all Stage 8 LPI blades. Observed "mass loss" failures of 5th stage blades from all LP turbines. Stage 5 blade failures were attributed to wheel resonance and possibly water accumulation.	Automatic reactor trip at 15% power due to thrust wear, subsequently the automatic thrust wear trip was defeated.		Five blades in Stage 4 of LP 3 turbine experienced fatigue failure with adjacent shroud damage. Failures attributed to high loading on Stage 4 caused by the previous removal of Stage 5 blades. Replaced Stage 4 blades with "pressure plates."	Refueling outage 2. Replaced Stage 4 blades in all 3 LP turbines. Used original blade design with "understraps" to provide continuous shroud interconnection. Replaced all Stage 8 LP 2 blades.	Refueling Outage 3. Did not replace any 8th stage blades of LP 3. Performed a limited inspection of turbine blades.			Plant modified steam control valves to increase power production to 105%. Removal of control valve guide tubes created steam oscillations. Plant reduced power to 93% to eliminate the oscillations which resulted from the control valve modifications.	
Turbine Synchro-nized	Com-mercial Oper-ation			Manual Rx trip on high bearing vibration.		One Stage 7 blade had "random cracking" in a blade root.					Moisture separator reheater bellows failure. Plant continues operation for several days while loss of extraction steam resulted in a loss of about 50 MW output.	Moisture separator reheater bellows failure. Plant continues operation for several days while loss of extraction steam resulted in a loss of about 50 MW output.		Turbine/ generator / exciter failure

APPENDIX B

APPENDIX C

NRC AUGMENTED INSPECTION TEAM EXIT MEETING
January 19, 1994

LIST OF ATTENDEES

Detroit Edison Company

D. Gipson, Senior Vice President, Nuclear Generation
G. Barker, Consultant
J. Bragg, Group Leader, Audits
N. Carrol, Clerk, Nuclear Information
G. Cerrullo, Senior Nuclear Information Specialist
L. Collins, Supervisor, Electrical
D. Delong, Superintendent, Radiation Protection
B. Eberhardt, Assistant to the Plant Manager
D. Eisenhut, Nuclear safety Review Group Chairman
P. Fessler, Technical Manager
L. Fron, Supervisor, Turbine
L. Goodman, Director, Nuclear Quality Assurance
M. Hall, Supervisor, Licensed Operator Requalification
P. Hudson, Systems Engineer
L. Kessler, Corporate Communications
E. Kokowski, General Supervisor, Radiation Protection
L. Layton, Supervisor, Nuclear Information Public Affairs
B. Lemieux, Plant Support
P. Marquart, Corporate Legal
B. Miller, Superintendent, Technical Engineering
K. Morris, Supervisor, RERP
B. Newkirk, Director, Nuclear Licensing
J. Nolloth, Superintendent, Maintenance
D. Ockerman, Director, Nuclear Training
G. Ohlemacher, Senior Engineer, Licensing
J. Plona, Superintendent, Plant Operations
B. Stafford, Nuclear Assurance Manager
G. Steiss, Photographer
J. Tibai, Principal Compliance Engineer

Nuclear Regulatory Commission

J. Martin, Regional Administrator, RIII
E. Greenman, Director, DRP, RIII
M. Bielby, AIT Team Member
R. Blough, NRR
T. Colburn, NRR
C. Crawford, Fermi Office Assistant
A. Dauginas, Public Affairs
W. Dean, EDO's Office
R. Gardner, AIT Team Leader
W. Kropp, AIT Assistant Team Leader
J. McCormick-Barger, AIT Team Member
H. Ornstein, AIT Team Member
S. Orth, AIT Team Member
M. Phillips, RIII
J. Stang, AIT Team Member
C. Willis, AIT Team Member

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
801 WARRENVILLE ROAD
LISLE, ILLINOIS 60532-4351

APPENDIX D

DEC 29 1993

Docket No. 50-341

MEMORANDUM FOR: Ron Gardner, Team Leader, Fermi 2 Augmented Inspection Team

FROM: Edward G. Greenman, Director, Division of Reactor Projects

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER FOR REVIEW OF THE DECEMBER 25, 1993, TURBINE GENERATOR FAILURE AT FERMI 2

As a result of the December 25, 1993, turbine generator failure with complications at Fermi 2, the Regional Administrator, along with NRR and AEOD senior management, determined that an Augmented Inspection Team (AIT) inspection should be conducted to verify the circumstances and evaluate the significance of the subject event.

AIT formation, per MC 0513, was based on the following: the staff's need to fully understand the causes and consequences of the turbine generator failure, which are unknown at this time; the staff's need to determine if there are potential generic issues worthy of staff action associated with the event; and the need to evaluate the significant and unexpected system interactions (water conductivity in the reactor vessel exceeds technical specification limits by an order of magnitude).

The Division of Reactor Safety (DRS) will conduct the AIT inspection and is responsible for the timely issuance of the inspection report. The Division of Reactor Projects (DRP) is responsible for managerial oversight and continuity from DRP's initial response to the event, identification and processing of potentially generic issues found, and the completion of any enforcement action warranted as a result of the Team's review. Both technical divisions concur with this approach.

Enclosed is the final Charter developed for the AIT delineating the scope of this inspection. This Charter was prepared in accordance with the NRC Incident Investigation Manual and Inspection Manual Chapter 0325, AIT. As stated, the objectives of the AIT are to communicate the facts surrounding this event to regional and headquarters management, to identify and communicate any generic safety concerns related to this event to regional and headquarters management, and to document the findings and conclusions of the onsite inspection. The inspection shall be conducted in accordance with NRC MC 0513, NRC Inspection Manual 0325, Inspection Procedure 93800, which I am enclosing for the team's use, and this memorandum.

If you have any questions regarding these objectives or the enclosed Charter, please do not hesitate to contact me.

Edward G. Greenman

Edward G. Greenman, Director
Division of Reactor Projects

Enclosures:
1. AIT Charter
2. NRC MC 0513
3. NRC Inspection MC 0325
4. Inspection Proc. 93800

cc w/enclosure 1 only:
J. B. Martin, RIII
H. J. Miller, RIII
F. J. Miraglia, NRR
L. J. Callan, NRR
C. E. Rossi, NRR
G. M. Holahan, NRR
A. E. Chaffee, NRR
J. A. Zwolinski, NRR
B. A. Boger, NRR
E. L. Jordan, AEOD
W. M. Dean, EDO
T. J. Colburn, LPM, NRR
W. J. Kropp, SRI, Fermi Site

January 7, 1994

Docket No. 50-341

MEMORANDUM FOR: Ron Gardner, Team Leader, Fermi 2 Augmented Inspection Team

FROM: Edward G. Greenman, Director, Division of Reactor Projects

SUBJECT: REVISED AUGMENTED INSPECTION TEAM CHARTER FOR REVIEW OF THE DECEMBER 25, 1993, TURBINE GENERATOR FAILURE AT FERMI 2

Based on the initial review of damage at the facility, and the evaluation the Regional Administrator and I conducted January 4, 1994, the Charter for the Augmented Inspection Team has been revised to focus on those activities that the licensee will complete in the near term or can be completed within the time period normally expected for performance of this inspection. It was clear to us that we should immediately focus on the water management issues at Fermi. This resulted in dispatching additional specialists and the independent measurements van to focus on this aspect of the recovery. This revised Charter is attached, and has been agreed upon by the Region III Office, NRR, and AEOD.

The objectives of the AIT continue to be the communication of facts surrounding this event to regional and headquarters management, identification of any generic safety concerns identified by the AIT to regional and headquarters management, and documentation of the findings and conclusions of the onsite inspection.

If you have any questions regarding these objectives or the enclosed Charter, please do not hesitate to contact me.

Original signed by Edward G. Greenman

Edward G. Greenman, Director
Division of Reactor Projects

Attachment: As stated

Distribution:

cc w/attachment:
J. B. Martin, RIII
H. J. Miller, RIII
F. J. Miraglia, NRR
L. J. Callan, NRR
C. E. Rossi, NRR
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E. L. Jordan, AEOD
W. M. Dean, EDO
T. J. Colburn, LPM, NRR
W. J. Kropp, SRI, Fermi Site

REVISED AUGMENTED INSPECTION TEAM (AIT) CHARTER

The Augmented Inspection Team (AIT) is to perform an inspection to accomplish the following:

1. Assess any previous turbine generator or support system problems that existed or occurred before the event, such as vibrational concerns; the licensee's handling of the information notice issued after the Salem turbine generator failure; and results from previous turbine blade examination or testing programs. (Review the functioning of the turbine protection systems, their interactions, and any subsequent effects on other plant systems that may have occurred during this event if the licensee has developed this information.)

2. Develop and validate the sequence of events and ongoing activities before and after the event.

3. Evaluate Detroit Edison's actions following the event. Include the implementation of the Emergency Plan, the response of operators, fire fighting actions, response of management, the availability of sufficient cognizant staff, and implementation of any additional needed fire protection, or event reporting.

4. Determine and evaluate the response of plant systems needed to cope with this event and the impact of the event on, or threat to, the operability of safety-related systems, including operation of those MOVs which did not function as expected.

5. Interview plant personnel and evaluate the operators' response to the event and their ability to quickly and safely stabilize the plant in a shutdown condition. Determine if personnel actions and procedural guidance were adequate.

6. Review the adequacy of DECo's turbine generator action plan.

7. Evaluate acceptability of the licensee's plans for recovery and disposition of the water and oil at the facility. The evaluation should consider the issue of mixed waste, and capabilities for water processing.

8. Confirm, through independent measurement, licensee's capabilities to determine radiological content of liquid samples, including potential discharges to the environment. Evaluate the licensee's plans for coordination with other regulatory interests, if required, regarding effluent releases. Quantify the initial releases following the event, both monitored and unmonitored, and compare to regulatory requirements and ODCM.

9. Evaluate acceptability of occupational health physics plans for the recovery efforts associated with both the water and oil activities and the turbine activities.

10. Review DECo determination as to the validity of the original turbine missile hazard analysis.

11. Determine if there are any other potential generic issues associated with this event.

12. Prepare a report documenting the results of this review for signature by the Director, Division of Reactor Projects, and concurrences by the Directors, Division of Reactor Safety and Division of Radiation Safety and Safeguards, within two weeks of the completion of this inspection.

AUGMENTED INSPECTION TEAM (AIT) CHARTER

AIT formation, per MC 0513, was based on the following: the staff's need to fully understand the causes and consequences of the turbine generator failure, which are unknown at this time; the staff's need to determine if there are potential generic issues worthy of staff action associated with the event; and the need to evaluate the significant and unexpected system interactions (water conductivity in the reactor vessel exceeds technical specification limits by an order of magnitude).

The Augmented Inspection Team (AIT) is to perform an inspection to accomplish the following:

1. Determine the specific circumstances and events which led up to the turbine generator failure. Include in your assessments any previous turbine generator or support system problems that existed or occurred before the event, such as vibrational concerns; the licensee's handling of the information notice issued after the Salem turbine generator failure; and results from previous turbine blade examination or testing programs. Review the functioning of the turbine protection systems, their interactions, and any subsequent effects on other plant systems. Also, determine the most likely root cause of the event and identify any generic implications or vulnerabilities for similar turbine generators.

2. Develop and validate the sequence of events and ongoing activities before and after the event.

3. Evaluate Detroit Edison's actions following the event. Include the implementation of the Emergency Plan, the response of operators, fire fighting actions, response of management, the availability of sufficient cognizant staff, and implementation of any additional needed safeguards, fire protection, or event reporting.

4. Determine and evaluate the response of plant systems needed to cope with this event and the impact of the event on, or threat to, the operability of safety-related systems, including operation of those MOVs which did not function as expected.

5. Interview plant personnel and evaluate the operators' response to the event and their ability to quickly and safely stabilize the plant in a shutdown condition. Determine if personnel actions and procedural guidance were adequate.

6. Review DECo root cause analysis of the event as well as any corrective actions which they tentatively propose. Review DECo plans and schedule for repairing the damage to the facility and returning the unit to service.

7. Review the adequacy of the licensee's program for evaluating these events. Oversee troubleshooting, testing, and analysis of the quarantined equipment.

8. Review the data on water chemistry and DECo's actions to evaluate the effects of abnormal chemistry conditions on stress corrosion of the exposed system components, including the fuel.

9. Review DECo determination as to the validity of the original turbine missile hazard analysis.

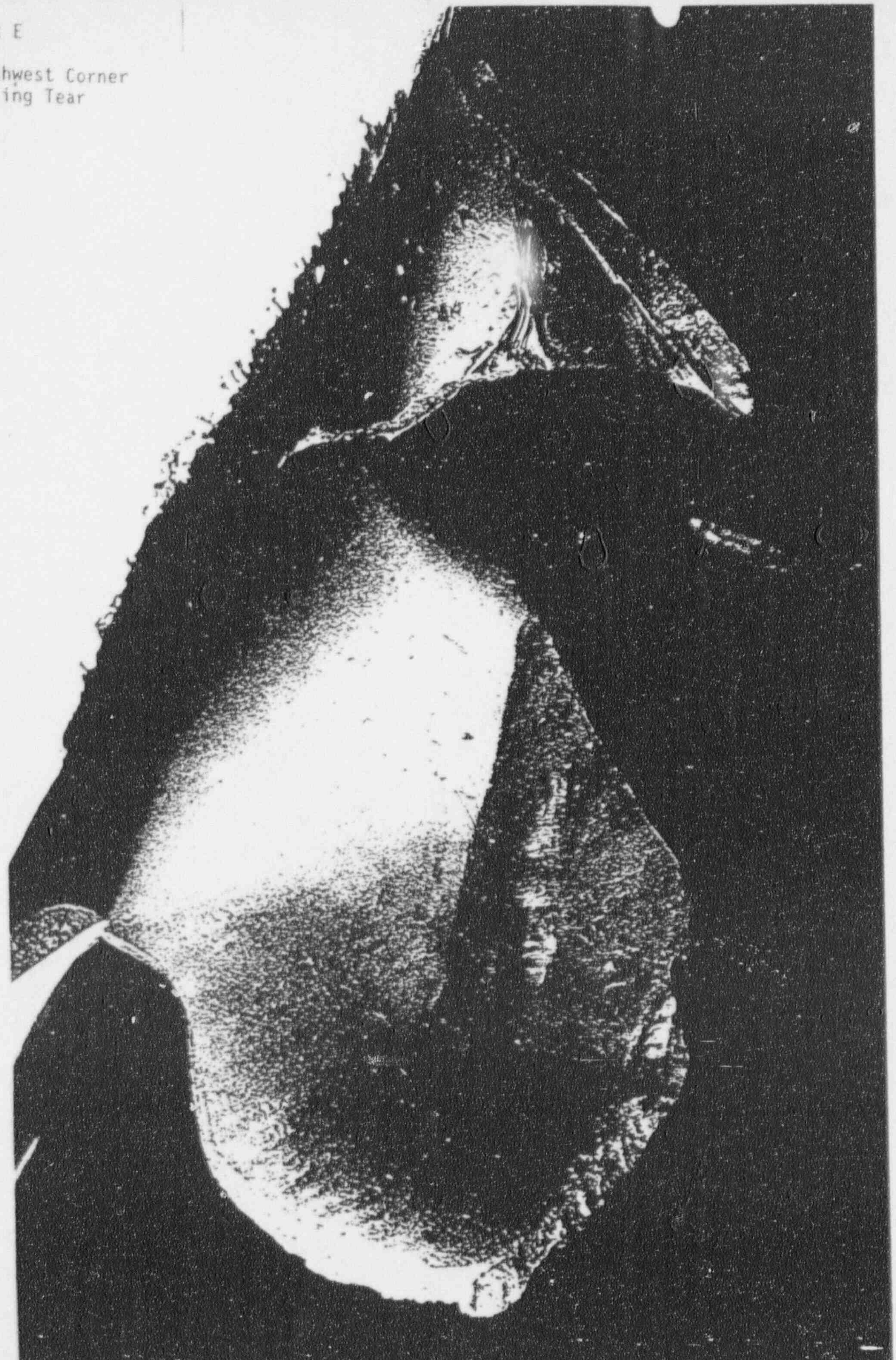
10. Determine if there are any other potential generic issues associated with this event.

11. Prepare a report documenting the results of this review for signature by the Director, Division of Reactor Projects within two weeks of the completion of this inspection.

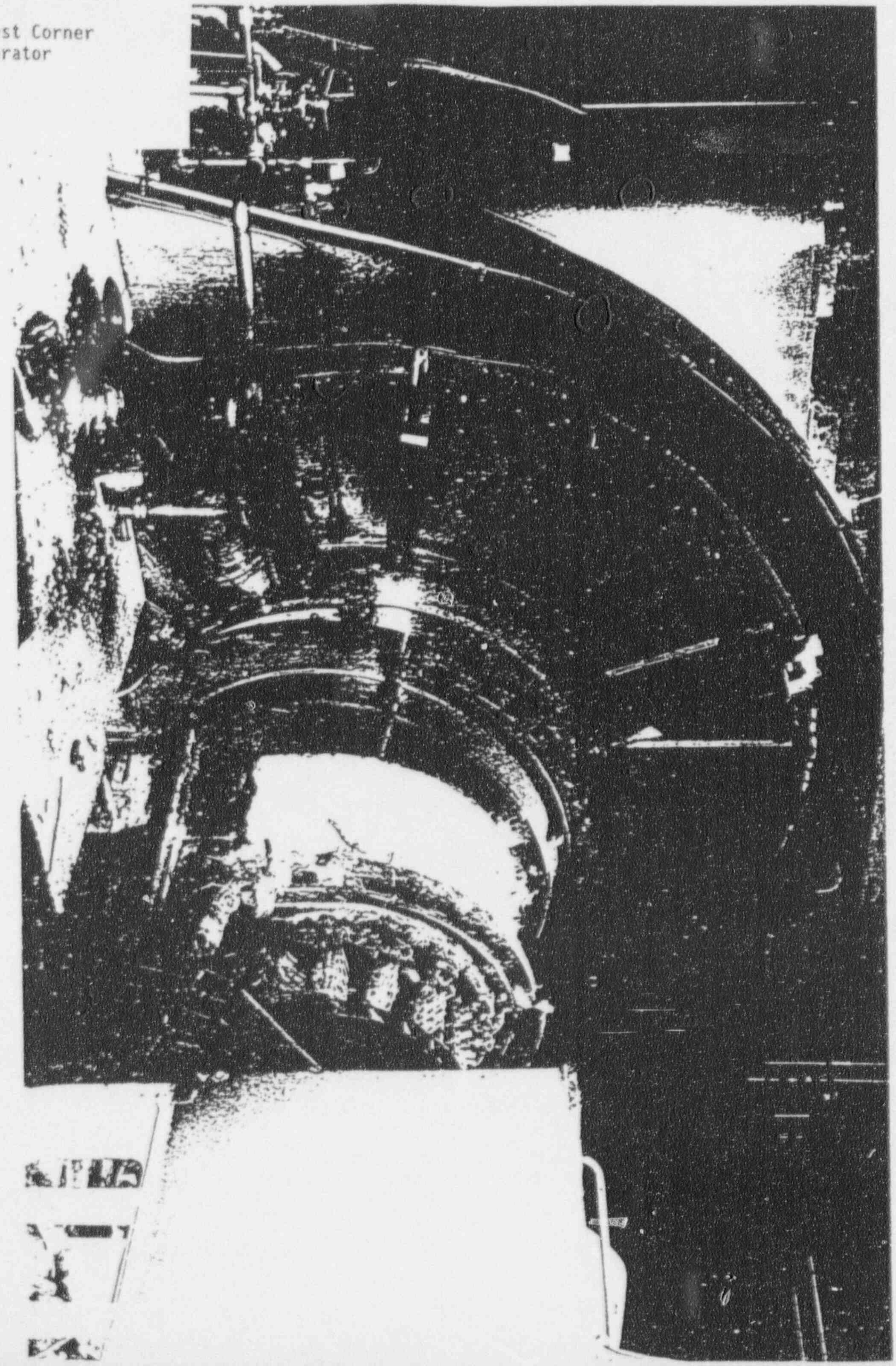
Stage 8
Blade Piece Located
Near #4 LP Valves

Appendix E

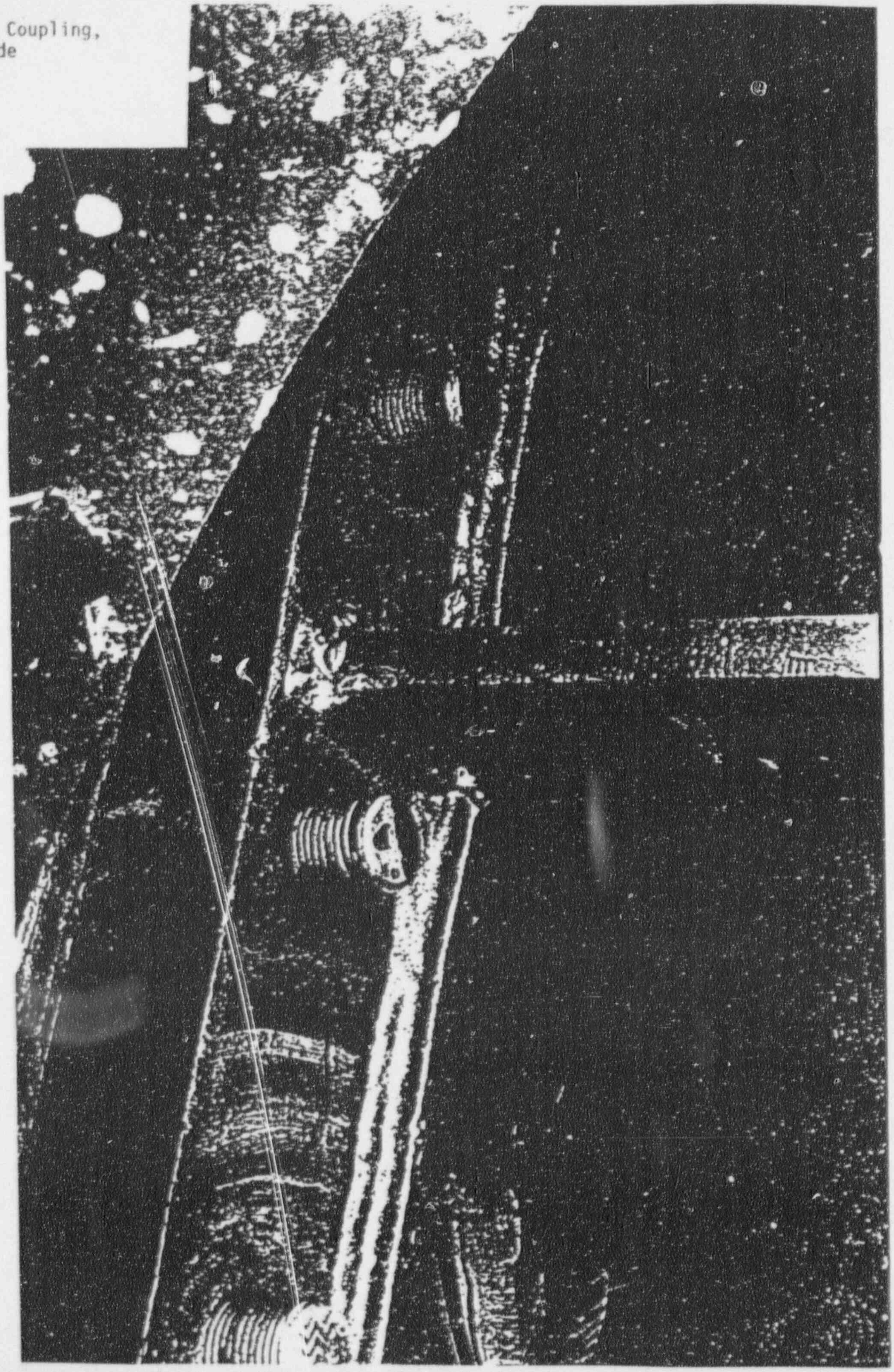
LP3 Northwest Corner
Housing Tear



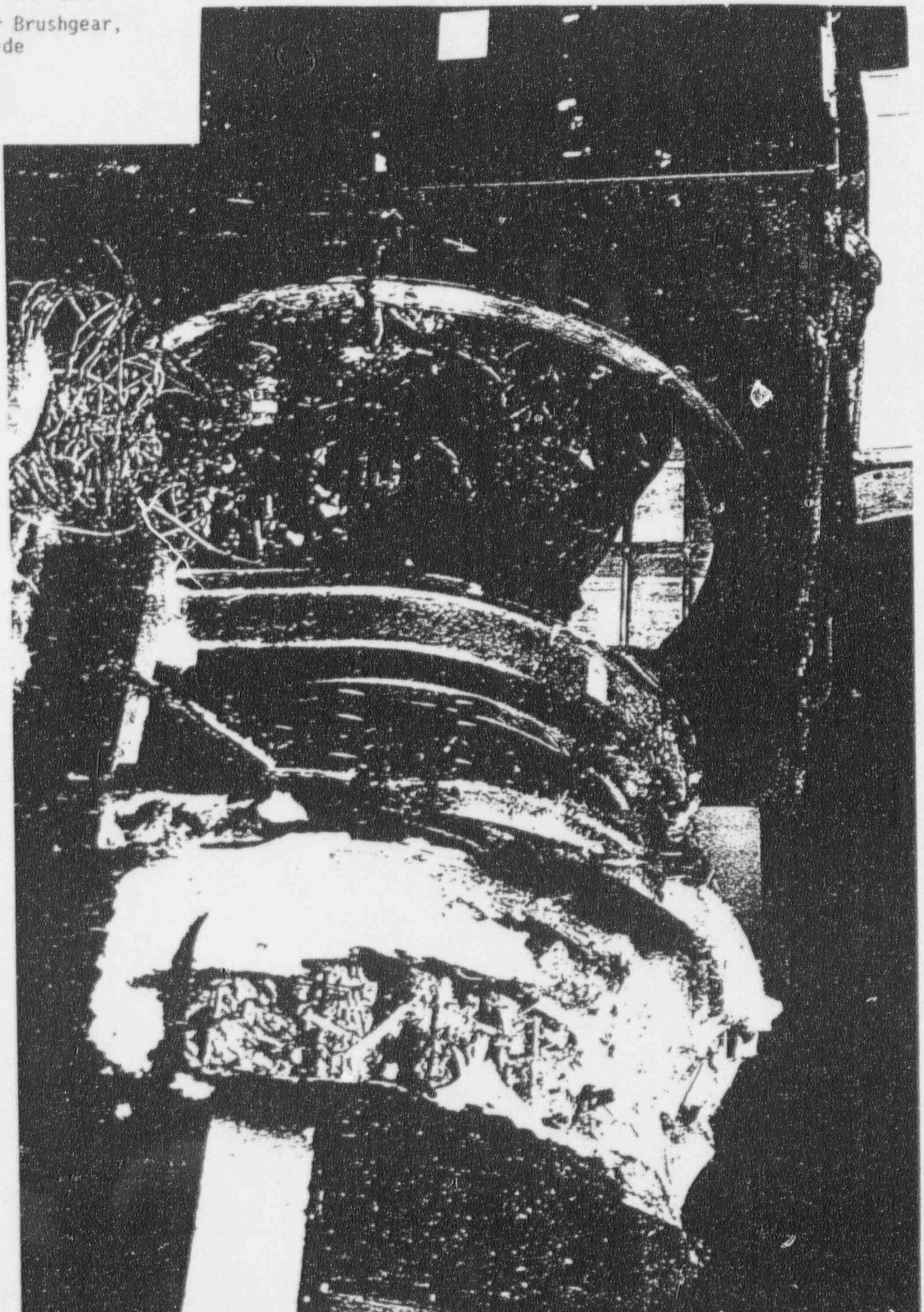
Southwest Corner
of Generator



Turbine Coupling,
East Side



Exciter Brushgear,
East Side



APPENDIX F

Radiological Environmental Monitoring
Fermi Unit 2
January 5-14, 1994

Sample Type (units)	Sample Number(s)	Sample Location	Results[1]
Water (pCi/l)	94-017	Storm Drain	< MDA[2]
	94-018	Lake Water (near CST[3])	< MDA
	94-019	Fermi 2 GSW[4] Intake	< MDA
	94-021	Lake Water (near Fermi 2 Discharge Line)	< MDA
	94-022; 94-036 94-037	Circulating Water Reservoir at Pump House	< MDA
	94-023	Circulating Water Reservoir (NE)	< MDA
	94-028	Surface Water at Fermi 2 GSW[4] intake	< MDA
	94-029	Surface Water at Monroe Drinking Water intake	< MDA
	94-030; 94-031	Overflow Canal	< MDA
	94-032	Lake Erie at mouth of Overflow Canal	< MDA
Sediment (pCi/kg)	94-020	Fermi 1 Intake	Cs-137=20.8

Notes:

1 These results are based on gamma isotopic analyses performed at the Fermi 2 site in the NRC Region III mobile laboratory with a high purity germanium detector. Naturally occurring radionuclides (i.e., thorium, radon, potassium) were detected but are not reported in this table.

APPENDIX F

Radiological Environmental Monitoring
Fermi Unit 2
January 5-14, 1994

(Continued)

[2] MDA - Minimum Detectable Activity
The MDA is defined as 4.66 * the one sigma error of the background sample analysis.

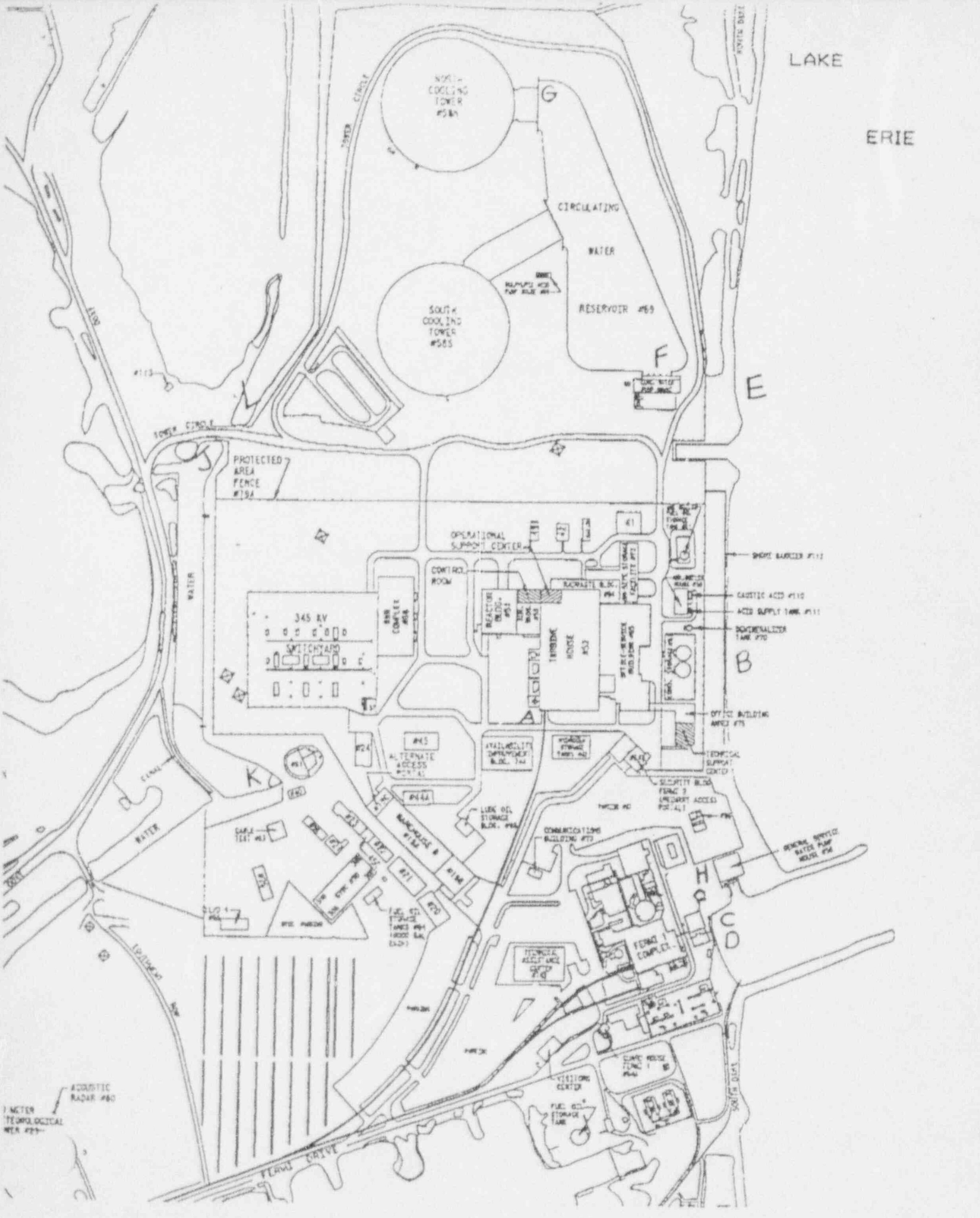
[3] CST - Condensate Storage Tank

[4] GSW - General Service Water

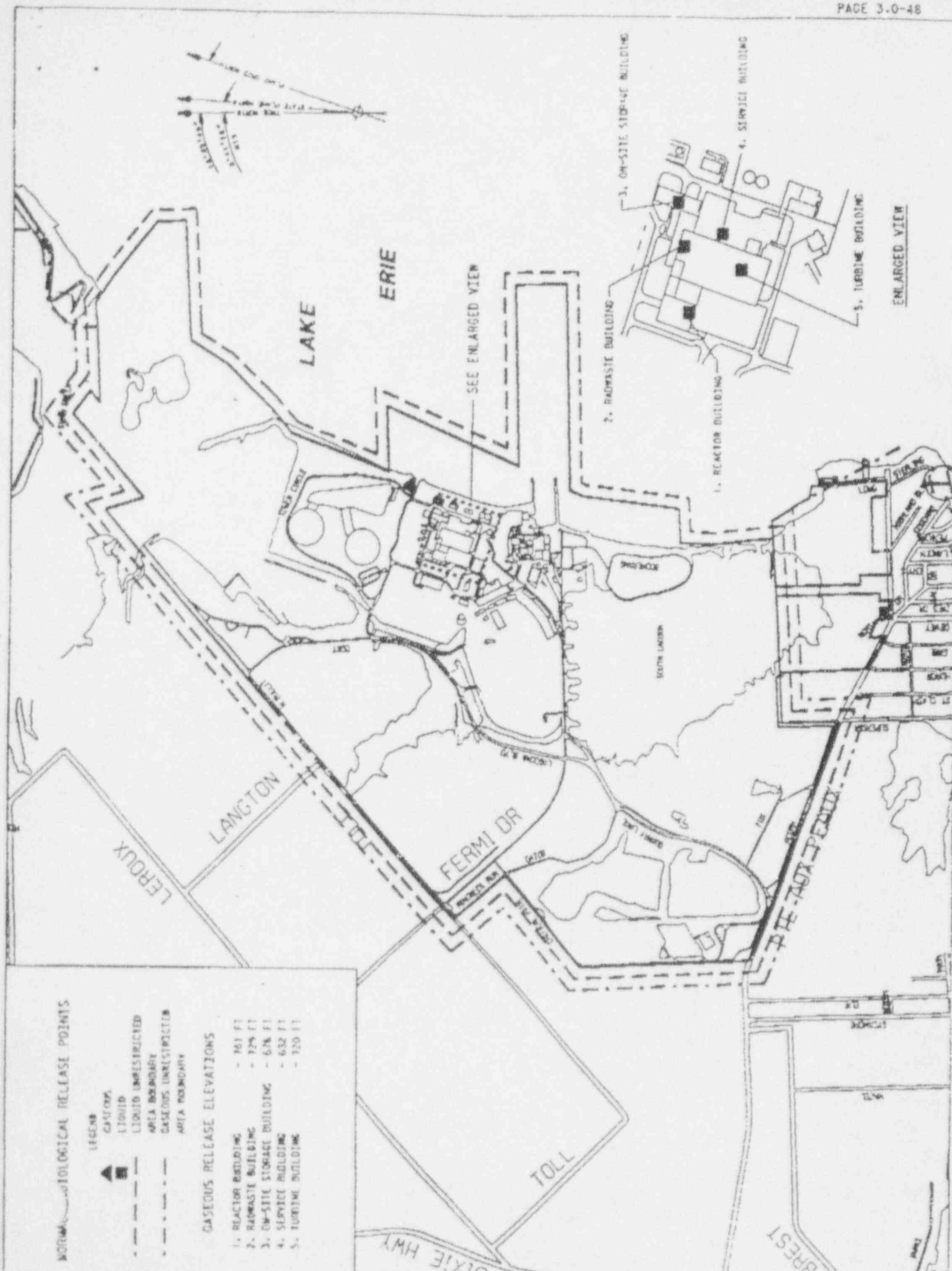
APPENDIX G

ENVIRONMENTAL SAMPLE SITES

SAMPLE DESCRIPTION	SAMPLE NUMBER	MAP LOCATION
Turbine Building Manhole	94-017	A
Shoreline East of CST	94-018	B
Fermi 1 GSW Intake	94-019	C
Fermi 1 GSW Sediment	94-020	D
Fermi 2 Discharge	94-021	E
Circwater Pumphouse Intake	94-022	F
NW Corner, Circwater Res.	94-023	G
Fermi 2 GSW (SW-3)	94-028	H
Monroe Water Intake (DW-1)	94-029	I
South Overflow Canal, Bridge	94-030	J
Overflow Canal, Discharge	94-031	K
Northside, Overflow Canal	94-032	L


LAKE
ERIE
TOWER CIRCLE
COOLING TOWER
G
CIRCULATING
WATER
RESERVOIR #69
SOUTH
COOLING
TOWER
#58S
F
E
PROTECTED
AREA
FENCE
#79A
OPERATIONAL
SUPPORT CENTER
CONTROL
ROOM
345 KV
SWITCHYARD
REACTOR
BLDG.
TURBINE
HOUSE
#52
RADWASTE BLDG.
CAUSTIC ACID #110
ACID SUPPLY TANK #111
DEMINERALIZER
TANK #70
B
A
OFFICE BUILDING
ANNEX #75
TECHNICAL
SUPPORT
CENTER
SECURITY BLDG.
ALTERNATE
ACCESS
PORTAL
AVAILABILITY
IMPROVEMENT
BLDG.
K
WATER
CANAL
LUBE OIL
STORAGE
BLDG.
COMMUNICATIONS
BUILDING #77
H
C
D
FERMI 1
COMPLEX
FUEL OIL
STORAGE
TANK
VISITORS
CENTER
FERMI DRIVE
SOUTH DIKE
NORTH DIKE
ACOUSTIC
RADAR #60

TOTAL P.02



MAP DEFINING UNRESTR. D AREAS AND SITE BOUNDARY FOR
RADIOACTIVE GASEOUS AND LIC. D EFFLUENTS

APPENDIX H

U.S. NUCLEAR REGULATORY COMMISSION
REGION III
CONFIRMATORY MEASUREMENTS
FERMI 2 NUCLEAR SITE

SAMPLE	NUCLIDE	NRC VAL[1] (uCi/ml)	NRC ERR[2] (uCi/ml)	LIC VAL[3] (uCi/ml)	LIC ERR[4] (uCi/ml)	RATIO[5]	RES[6]	RESLT[7]
RAD WASTE BLDG WATER DET 2	CR-51	1.39E-04	1.13E-06	1.37E-04	9.16E-06	0.99	123.0	A
	MN-54	1.95E-05	1.53E-07	2.12E-05	1.00E-06	1.09	127.5	A
	CO-58	8.59E-06	1.13E-07	7.85E-06	7.01E-07	0.91	76.0	A
	CO-60	2.87E-05	1.83E-07	3.40E-05	1.23E-06	1.18	156.8	A
	ZN-65	9.62E-06	2.45E-07	1.04E-05	1.25E-06	1.08	39.3	A
	I-131	2.81E-05	1.63E-07	2.85E-05	1.34E-06	1.01	172.4	A
	CD-109	6.26E-06	1.44E-06	0.00E+00	0.00E+00		4.3	NC
	CS-134	6.23E-05	2.30E-07	6.79E-05	1.67E-06	1.09	270.9	A
	CS-136	3.15E-06	1.10E-07	0.00E+00	0.00E+00		28.6	NC
	CS-137	5.59E-05	2.37E-07	5.45E-05	1.46E-06	0.98	235.9	A
BASMT 2" ABOVE FLOOR DET 2	CR-51	1.17E-04	2.24E-06	1.22E-04	3.05E-06	1.04	52.3	A
	MN-54	2.55E-05	3.15E-07	2.67E-05	4.31E-07	1.05	80.9	A
	CO-58	1.08E-05	2.45E-07	1.11E-05	3.32E-07	1.02	44.2	A
	CO-60	3.97E-05	4.08E-07	4.35E-05	5.23E-07	1.09	97.3	A
	ZN-65	1.09E-05	4.86E-07	1.15E-05	6.00E-07	1.06	22.3	A
	I-131	2.33E-05	3.53E-07	2.39E-05	4.19E-07	1.03	65.9	A
	CS-134	9.70E-05	5.44E-07	1.05E-04	7.06E-07	1.08	178.3	A
	CS-136	3.89E-06	2.31E-07	4.34E-06	3.09E-07	1.12	16.8	A
	CS-137	8.75E-05	5.42E-07	8.75E-05	6.75E-07	1.00	161.5	A
RW BASMT FLOOR DET 1	CR-51	1.15E-04	2.10E-06	1.24E-04	4.76E-06	1.07	54.8	A
	MN-54	2.22E-05	3.17E-07	2.41E-05	6.66E-07	1.09	70.1	A
	CO-58	9.07E-06	2.35E-07	1.00E-05	4.83E-07	1.11	38.6	A
	CO-60	3.28E-05	3.65E-07	3.84E-05	7.52E-07	1.17	90.0	A
	ZN-65	9.15E-06	4.41E-07	1.19E-05	9.55E-07	1.30	20.7	A
	I-131	2.09E-05	3.24E-07	2.37E-05	9.31E-07	1.14	64.4	A
	CS-134	7.67E-05	4.91E-07	9.04E-05	1.06E-06	1.18	156.5	A
	CS-136	3.48E-06	2.43E-07	3.92E-06	3.81E-07	1.13	14.3	A
	CS-137	6.90E-05	4.85E-07	7.23E-05	9.80E-07	1.05	142.1	A

APPENDIX H

U.S. NUCLEAR REGULATORY COMMISSION
REGION III
CONFIRMATORY MEASUREMENTS
FERMI 2 NUCLEAR SITE

(Continued)

SAMPLE	NUCLIDE	NRC VAL[1] (uCi/ml)	NRC ERR[2] (uCi/ml)	LIC VAL[3] (uCi/ml)	LIC ERR[4] (uCi/ml)	RATIO[5]	RES[6]	RESLT[7]
RW BASMT	CR-51	1.15E-04	2.10E-06	1.28E-04	2.96E-06	1.11	54.8	A
FLOOR	MN-54	2.22E-05	3.17E-07	2.40E-05	3.88E-07	1.08	70.1	A
DET 2	CO-58	9.07E-06	2.35E-07	9.96E-06	3.32E-07	1.10	38.6	A
	CO-60	3.28E-05	3.65E-07	3.66E-05	4.95E-07	1.11	90.0	A
	ZN-65	9.15E-06	4.41E-07	9.90E-06	5.90E-07	1.08	20.7	A
	I-131	2.09E-05	3.24E-07	2.20E-05	4.64E-07	1.05	64.4	A
	CS-134	7.67E-05	4.91E-07	8.62E-05	6.40E-07	1.12	156.5	A
	CS-136	3.48E-06	2.43E-07	3.71E-06	2.77E-07	1.07	14.3	A
	CS-137	6.90E-05	4.85E-07	7.22E-05	6.24E-07	1.05	142.1	A
CST	CR-51	8.26E-06	6.73E-07	1.21E-05	1.26E-06	1.46	12.3	A
'K	MN-54	6.52E-07	6.38E-08	6.74E-07	1.20E-07	1.03	10.2	A
1	CO-60	6.37E-07	5.96E-08	8.42E-07	1.06E-07	1.32	10.7	A
	I-131	1.55E-06	9.50E-08	2.06E-06	1.91E-07	1.33	16.3	A
	CS-134	7.85E-06	1.50E-07	9.43E-06	2.83E-07	1.20	52.4	A
	CS-136	2.49E-07	5.52E-08	0.00E+00	0.00E+00		4.5	NC
	CS-137	7.22E-06	1.49E-07	7.47E-06	2.72E-07	1.04	48.4	A
CST	CR-51	8.26E-06	6.73E-07	9.58E-06	7.52E-07	1.16	12.3	A
TANK	MN-54	6.52E-07	6.38E-08	7.20E-07	6.69E-08	1.10	10.2	A
DET 2	CO-60	6.37E-07	5.96E-08	6.61E-07	7.11E-08	1.04	10.7	A
	I-131	1.55E-06	9.50E-08	1.64E-06	1.12E-07	1.06	16.3	A
	CS-134	7.85E-06	1.50E-07	8.47E-06	1.86E-07	1.08	52.4	A
	CS-136	2.49E-07	5.52E-08	3.81E-07	6.61E-08	1.53	4.5	A
	CS-137	7.22E-06	1.49E-07	7.10E-06	1.80E-07	0.98	48.4	A

1 This value represents the isotopic results of the analysis performed with a high purity germanium detector in the Region III mobile laboratory at the Fermi 2 site.

2 This value represents the one sigma counting error of the NRC analysis.

APPENDIX H

U.S. NUCLEAR REGULATORY COMMISSION
REGION III
CONFIRMATORY MEASUREMENTS
FERMI 2 NUCLEAR SITE

(Continued)

[1] This value represents the isotopic results of the analysis performed with one of two high purity germanium detetectors maintained and operated by the Fermi 2 chemistry staff. The detector used for the analysis is denoted in column one of the above table.

[2] This value represents the one sigma counting error of the licensee's analysis.

[3] The ratio is defined as the licensee result divided by the NRC result.

[4] This value represents the resolution of the NRC analysis. The resolution is defined as the quotient of the NRC result divided by the NRC one sigma error.

[5] The criteria for comparison is defined in attachment I, "Criteria for Comparing Analytical Results."

A = Agreement

D = Disagreement

NC = No comparison

APPENDIX I

CRITERIA FOR COMPARING ANALYTICAL MEASUREMENTS

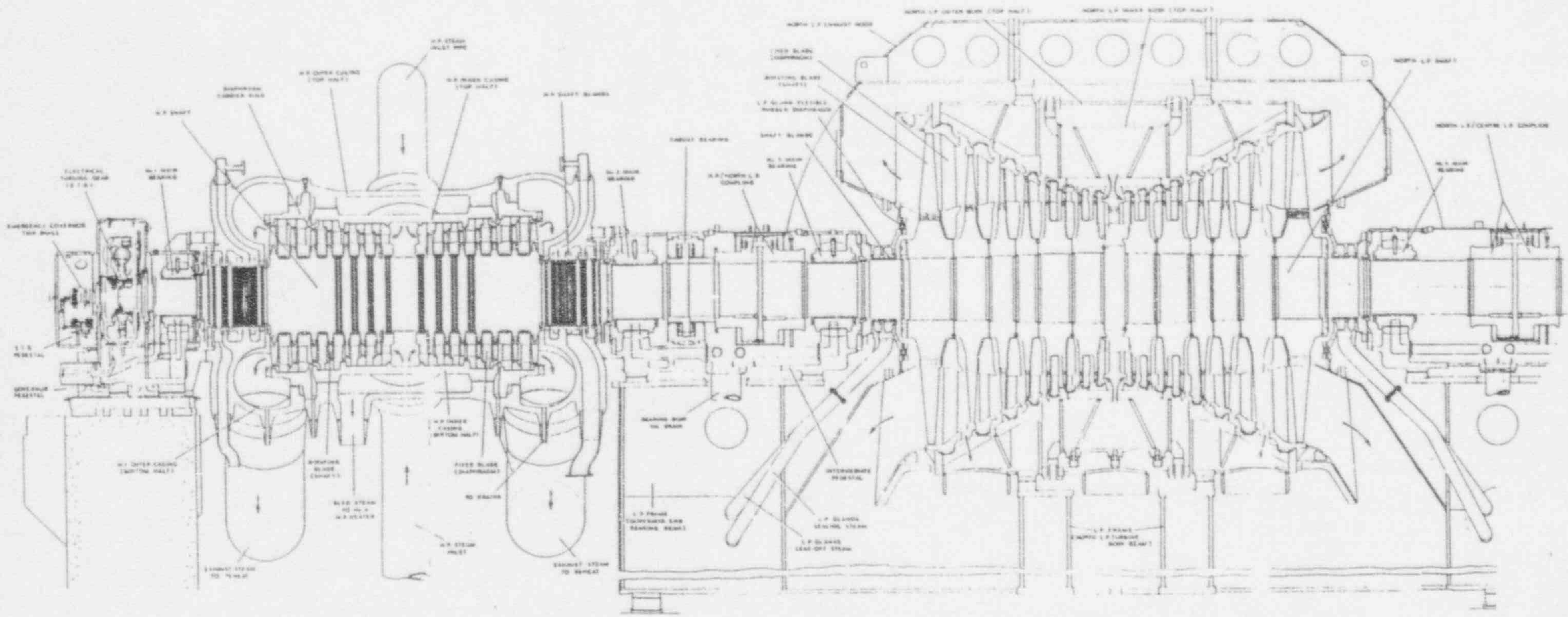
This attachment provides criteria for comparing results of capability tests and verification measurements. The criteria are based on an empirical relationship which combines prior experience and the accuracy needs of this program.

In these criteria, the judgement limits are variable in relation to comparisons of the NRC's value to its associated one sigma uncertainty. As that ratio, referred to in this program as "Resolution", increases, the acceptability of a licensee's measurement should be more selective. Conversely, poorer agreement should be considered acceptable as the resolution decreases. The values in the ratio criteria may be rounded to fewer significant figures reported by the NRC Reference Laboratory, unless such rounding will result in a narrowed category of acceptance.

RESOLUTION	RATIO = LICENSEE VALUE/ NRC REFERENCE VALUE
	AGREEMENT
< 4	NO COMPARISON
4 - 7	0.5 - 2.0
8 - 15	0.6 - 1.66
16 - 50	0.75 - 1.33
51 - 200	0.80 - 1.25
> 200	0.85 - 1.18

Some discrepancies may result from the use of different equipment, techniques, and for some specific nuclides. These may be factored into the acceptance criteria and identified on the data sheet.

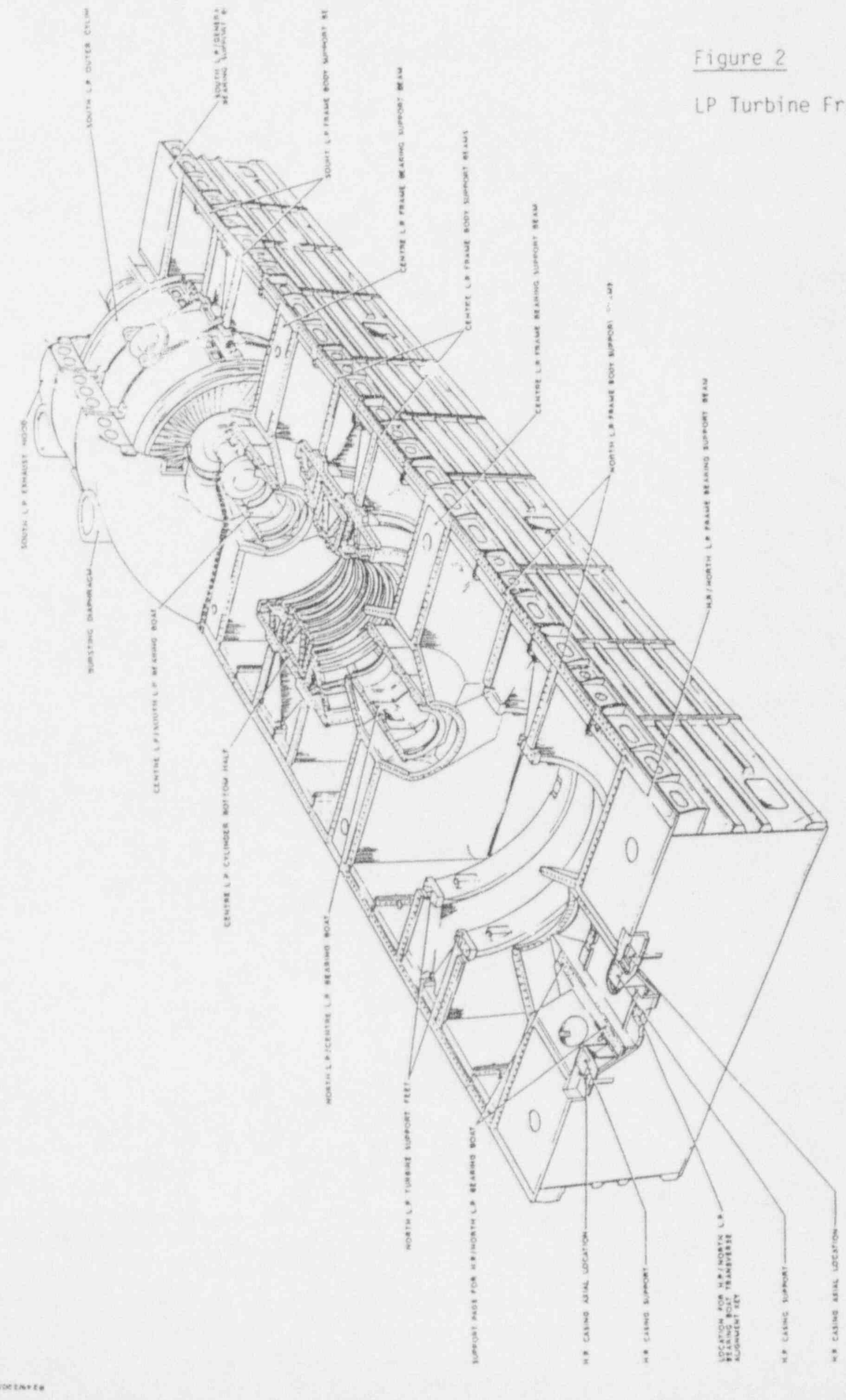
FIGURE



HP and LP Turbines

Figure 2

LP Turbine Frame



DIVISION OF REACTOR SAFETY

FACILITY: Fermi AIT REPORT NO. 93029

WRITE AMOUNT OF EACH TO BE REPRODUCED DATE MAILED: 2/7/94

12 Letter with concurrences, w/encl(s)

30 Letter without concurrences, w/encl(s)

— Report Only

5 766 Forms, Yellow/Gray Book Input Forms, Etc.

2 Letter Only with Concurrences

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Russell
Rossi
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Reyes
Spessard
Jordan
Hodges
Gibson
Grimes
Richards

1E01

RIII REPORT/LETTER TRAVELLER   Total days to issue: ____

Licensee: THE DETROIT EDISON CO. 6400 NORTH DIXIE HWY. NEWPORT, MI 48166	Draft Completion Date:	Report No.(s): 50-341/93029
Facility(s): FERMI 2 STATION	Initial Typing: ____ Received ____ Start ____	Inspection End Date:
License No.(s): NPF-43		Inspector(s): Gardner

Review Process

Doc For	Insp/PM In	Insp/PM Out	S.C. In	S.C. Out	B.C. In	B.C. Out	D.D. In	D.D. Out	In	Out	Data Mgmt.Unit In	Data Mgmt.Unit Out
Draft									Final		2/4	2/4

NOTES

Note No.	Comment

Issue Date: 2/7/94 Licensee; 2/8 HQ(DMB)

Proprietary Review Notif. Telephone ____ Due ____ Received

Licensee Response: N/A Due ____ Issued ____ Received

Thank You Letter: ____ Due ____ Issued

Form 591 Applicable? Yes ____ No ____
Issued From: Field ____ Office ____

Region III - RITS System
Inspection Report Tracking Subsystem (IRTS)
Data Input/Update Sheet

Instructions: Each record in this database is defined by the Docket Number and Report Number Combination. For each IRTS update, this specific data must be included. Upon completion of this form, please forward it to the Information Management Section (IMS), ATTN: Ida Ogle.

****

* Docket Number (1st Unit): 05000341 Report Number: 93-029 *

* Docket Number (2nd Unit): _ _ _ _ _ _ _ _ Report Number: _ _ - _ _ _ *

****

In order to effect changes in the IRTS database, please complete the following field updates, as necessary:

Lead Inspector: RON GARDNER

Type of Inspection: T T=Team, S=Salp, R=Regular

Date Inspection Ended: 01/19/94 (Actual or Projected)

Date Inspection Report Mailed: 02/04/94

Inspection Report Status Code: C C=Closed, O=Open, X=Cancelled

Licensee Response Required?: N Y=Yes, N=No

Date Licensee Response Received: _ _ /_ _ /_ _

Special Comments or Instructions: ______________________________

Form Completed By: Ron Gardner Date: 2/4/94

File: C:\WP51\WPDOCS\IRTSFORM.WPF Revised 7/10/92