U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-410/92-81

Docket No. 50-410

License No. NPF-69

Licensee: Niagara Mohawk Power Corporation
301 Plainfield Road
Syracuse, New York 13212

Facility Name: Nine Mile Point Nuclear Power Station, Unit 2

Inspection At: Scriba, New York

Conducted: March 24-28, 1992

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EXECUTIVE SUMMARY

On March 23, 1992, at about 10:00 a.m., licensee personnel inadvertently tripped one of the two lines supplying offsite power to Nine Mile Point Nuclear Power Plant Unit 2, which was shutdown with about one-third of the core offloaded. The line loss led to a loss of control room annunciators and the declaration of an alert. The second offsite power line also was inadvertently tripped causing a total loss of offsite power. Several minutes later, one of the two running emergency diesel generators (EDGs) tripped, due to loss of cooling water.

An augmented inspection team (AIT) was dispatched by the NRC to determine the circumstances that led to this event, its causes, safety significance and generic implications, and the adequacy of the licensee's response to the event. The AIT began its assessments on March 24, 1992, completed its onsite reviews on March 28, 1992, and presented its preliminary findings in a public exit meeting on April 1, 1992.

A technician initiated the event by bumping contacts closed while replacing a glass relay cover. Human factors problems contributed to the inadvertent performance error.

One of the two sources of power to the control room annunciators (UPS 1A) lost power and was unable to transfer to another source due to an internal fault. The fault had been identified 14 days before the event, had been assigned a "C" priority (less than seven days), and had been scheduled for work 2 days after the event. This work delay indicates a need for review of oversight of work prioritization and scheduling.

The remaining annunciator power source (UPS 1B) was not able to sustain the load, tripped on overload within 30 seconds, and control room annunciators were lost. The current design represents a continued vulnerability to a loss of control room annunciators during shutdown or plant transients (high alarm and annunciator loads) if coincident with the loss of the non-safety UPS 1A.

The internal UPS 1A fault was found to be a failed internal logic battery. These batteries were replaced following the IIT with a planned replacement cycle of about 15 months. The bad battery was sent to the vendor by the licensee for a failure analysis. The earlier than expected failure (seven months vice planned fifteen months' replacement interval) requires followup.

Operator performance was acceptable. The total loss of offsite power was caused by a combination of inadequate work package plant impact assessment and inaccurate technician information. Weaknesses in management support to operations also contributed.

The Division III EDG tripped during the event due to the loss of service water cooling. This trip disclosed a previously unrecognized design vulnerability to a sequential loss of offsite power sources. That is, the offsite lines are lost not simultaneously, but separated by 15 seconds or more. In this scenario, should the first EDG fail or be out of service (as on March 23), then the Division III EDG will trip unless it is followed by rapid operator action. This represents a potential generic issue for plants with EDGs that don't supply their own auxiliary and support systems.

The consequences of this event were minimal. The facility was in refueling with the reactor cavity flooded. The reactor core and the reactor coolant system were unaffected, no equipment was damaged and no radioactivity was released.

1.0 INTRODUCTION

Upon being informed of the loss of offsite power and control room annunciators at Nine Mile Unit 2 on March 23, 1992, the NRC Region I Regional Administrator and senior management from the Office of Nuclear Reactor Regulation (NRR) and the Office for Analysis and Evaluation of Operational Data (AEOD) determined that an Augmented Inspection Team (AIT) should be formed to review and evaluate the circumstances and significance of this occurrence. The basis of the NRC concern was the apparent inadequacies of management controls of maintenance activities that allowed the event to occur. Accordingly, an AIT was selected, briefed, and the AIT leader dispatched to the site on March 24, 1992.

1.1 The AIT Scope and Objectives

The charter for the AIT (Appendix A) was finalized on March 24, 1992. The charter directed the team to conduct an inspection and accomplish the following objectives:

1. Conduct a timely, thorough and systematic review of the circumstances surrounding the event, including the sequence of events that led to and followed the March 23, 1992 loss of offsite power and control room annunciator;

2. Collect, analyze and document relevant data and factual information to determine the causes, conditions and circumstances pertaining to the event, including the response to the event by the licensee's operating staff;

3. Assess the safety significance of the event and communicate to Regional and Headquarters management the facts and safety concerns related to the problems identified; and

4. Evaluate the licensee's review of and response to the event and implemented corrective actions.

1.2 AIT Process

During the period March 24-28, 1992, the AIT conducted an independent inspection, review, and evaluation of the conditions and circumstances associated with this event. The team inspected the event-initiating relays, the offsite power supply breakers, control room annunciators' power supplier, and related indications in the control room; held discussions and formal interviews with personnel involved in this event; reviewed relevant records including computer printouts before, during, and after the event, and trends of pertinent

plant parameters; and evaluated the adequacy of established procedures, management oversight, and personnel training. Appendix B is the list of personnel contacted by the AIT and Appendix C is the list of documents reviewed by the AIT members.

This inspection was conducted in accordance with NRC Manual Chapter 0513, Part III, Inspection Procedure 93800, Regional Instruction 1010.1 and additional instructions provided in the AIT charter.

2.0 LOSS OF OFFSITE POWER AND CONTROL ROOM ANNUNCIATOR

2.1 Overview of Offsite and Onsite Power Systems

Nine Mile Point Unit 2 receives power from two offsite 115 kV lines, called line 5 and line 6. The breakers for these lines are located in the Scriba switchyard approximately one-half mile from the site. Figure 1 is a simplified one-line diagram of the portion of the electrical distribution involved in the March 23, 1992 event.

At the time of the event, line 5 was supplying power to the Division I and III buses through transformer RSST-A with R-50, motor-operated disconnect switch MDS-3 and the Division I and III breakers all shut. The auxiliary boilers were also being powered from line 5 with MDS-10, MDS-5, and the auxiliary boilers breaker shut. The Division II bus was being supplied by line 6 through R-60, MDS-4, transformer RSST-B and the Division II breaker. Open were MDS-20, the Division III breaker from transformer RSST-B and all the EDG breakers to their respective buses. The Division I EDG was out of service for planned maintenance and the Division II and III EDGs were aligned for automatic start on loss of power to their respective buses.

The Division III EDG is dedicated to supply power to the High Pressure Core Spray (HPCS) system. The remaining safety-related equipment is divided between Divisions I and II. The HPCS system was not required to be operable at the time of the event, but was available as a backup for adding water to the reactor coolant system and the flooded reactor cavity.

2.2 History and Design of Control Room Annunciation Power Supplier

The Nine Mile Point Unit 2 control room annunciators are powered jointly from two uninterruptible power supplies (UPS), UPS-1A and UPS-1B. Upon loss of one UPS, the annunciator power supply circuit of the other continues to supply all the loads alone. If an overload condition results, the remaining power supply would trip, as it did on March 23, 1992, and all control room annunciators would become deenergized.

Each UPS can supply the annunciators by using an ac or a dc (station batteries) input. A separate maintenance ac source also can be used to supply the annunciator circuit directly in case of UPS failure or planned UPS maintenance. Each UPS unit has a control logic module which monitors voltage and which initiates automatic transfers to maintain power to the annunciators. Each UPS control logic module also contains internal battery packs (three "D" cells per pack) for certain functions. Proper voltage from these internal batteries was necessary for annunciator power to be transferred from the maintenance supply and back to the UPS.

For additional details on UPS design, see NUREG-1455, "Transformer Failure and Common-Mode Loss of Instrument Power at Nine Mile Point Unit 2 on August 13, 1991."

2.3 Chronology of Events

The AIT compiled independently a detailed chronology of events by interviewing cognizant personnel, reviewing relevant records including computer printouts before, during, and after the event, and trends of pertinent plant parameters. This detailed chronology is provided in Table 1.

2.4 Highlights of the Event

2.4.1 Loss of Control Room Annunciators

On March 9, 1992, UPS-1A automatically transferred power, as designed, to the annunciators to the maintenance source. This transfer occurred due to a voltage fluctuation caused by testing on another circuit. The UPS-1A control logic sensed the voltage drop and properly initiated the transfer.

Licensee personnel were unable to return the annunciators to their normal source. The cause of this problem was not known and a Work Request (WR 201538) was initiated with a "C" priority (less than seven days) to troubleshoot the failure to transfer.

The loss of line 5 (see Section 2.4.2) on March 23, 1992, deenergized the annunciator circuits powered from UPS-1A. Power remained available from the large station batteries but, as had been identified two weeks previously, UPS-1A was not able to transfer to another supply.

For a short period of time (less than 30 seconds), UPS-1B maintained the control room annunciators. Because the plant was shutdown, many alarms and annunciators were energized causing a high load on the circuit. UPS-1B was unable to continue to supply the demand alone, and the annunciator circuit tripped on overload.

Power was restored to the control room annunciators after about 80 minutes.

2.4.2 Loss of Offsite Power

On March 20, 1992, meter and test technicians began calibrating relays using an electrical preventive maintenance procedure (No. S-EPM-GEN-2Y070). The work package had been prepared a month earlier, but had been postponed as part of the work package review activities which were corrective actions following the Nine Mile Point Unit 1 loss of ultimate heat sink (see NRC Inspection Report 50-220/92-80). The plant impact assessment in the work package did not address effects should any of the relays actuate during the job.

On March 23, 1992, a technician inadvertently bumped contacts of the backup overcurrent protection relay on the "B" phase of the auxiliary boilers supply breaker. At the time, the technician had completed calibration of the relay and was replacing the glass cover. The meter and test personnel noted that a relay trip had occurred, notified the control room, and were directed to come to the control room to explain.

The auxiliary boiler relay trip (type 86) had also tripped the next breaker up the circuit (see Figure 1), R-50. The relay logic included two sets of contacts which effectively mimicked the power circuit up to MDS-5. Since R-50 and MDS-10 were closed, a current path existed which picked up another relay (type 94), which tripped R-50. At the time of the event, MDS-20 was open so no current path existed to actuate the type 94 relay for the line 6 breaker, R-60.

The trip of R-50 deenergized all equipment being supplied from line 5. This equipment included UPS-1A, two of the three air compressors, the Division I bus and the Division III bus. After about 10 seconds, the Division III EDG successfully completed an automatic start and restored power to the Division III bus. After about 20 seconds, control

room annunciators were lost due to the inability of the remaining power supply (UPS-1B) to sustain the load. The Division I bus, which had included one of the two running service water pumps, remained deenergized since its dedicated EDG was out of service for planned maintenance.

Control room operators took a number of initial actions in response to the event. These actions included dispatching an operator to the refuel floor to continuously monitor water level, debriefing the meter and test personnel on the cause of the event, and declaring an Alert in accordance with the licensee's Emergency Plan.

About 10 minutes after the event began, the last running air compressor tripped due to loss of cooling water caused by the loss of line 5. Air pressure, already dropping, began to fall more rapidly. Operators were concerned as to the continued leak tightness of the air bladder seals around the outside of the reactor vessel and in the submerged main steam lines.

About 18 minutes after line 5 tripped, control room operators attempted to restore power to the deenergized equipment (including the annunciators) by closing MDS-20 and using power from line 6. Control room operators had called the utility's offsite power control center in Syracuse and had been told that the travelling switchyard operator (based about 20 miles south of the plant in Fulton) would be radioed to go to the Scriba switchyard and close the offsite breakers. Syracuse personnel estimated a half hour response time.

The decision to use line 6 followed discussions with the meter and test personnel who stated that there were no problems with this approach. This operation also received the concurrence of the senior control room supervisor. The Operations Manager and the Plant Manager were also present at the time with the latter being briefed prior to assuming his role as the Emergency Director at the Technical Support Center.

The closure of MDS-20 completed the controls logic associated with the still tripped type 86 relay for the auxiliary boiler; this resulted in the trip of R-60 and the loss of line 6. At this time, Unit 2 had lost all offsite power (LOOP).

After about 10 seconds, the Division II EDG successfully completed an automatic start and reenergized the Division II bus. Shortly thereafter, SWP-1B automatically restarted which restored service water to Division II loads. Operators also promptly restarted RHS-P1B to restore shutdown cooling. There was no apparent rise in reactor coolant system temperature during the less than two minute interruption in shutdown cooling flow.

Service water cooling remained interrupted to the running Division III EDG due to a potential design deficiency (see Section 3.1.3). The Division III EDG tripped due to loss of cooling water after about seven minutes.

Control room operators, in conjunction with meter and test personnel, determined that failure to reset the initial tripped type 86 relay had caused the opening of R-60 upon MDS-20 closure. The type 86 relay was reset and the Fulton-based operator arrived at the Scriba switchyard and reclosed the R-50 and R-60 breakers. The initial attempt to restore power to the line 5 loads was not successful because MDS-3 would not close. Operators initiated a work request to troubleshoot MDS-3 but successfully used a different lineup (from line 6) to restore power. No problems were found during troubleshooting efforts and MDS-3 was later closed successfully.

Upon restoration of the control room annunciators, operators noted high reactor building sump level alarms. The levels were found to be the result of normal leakage which continued while the sump pumps were deenergized. After power was restored to the pumps, sump levels returned to normal.

The licensee restored the plant to a normal shutdown lineup and, after discussions with the NRC and offsite organizations, terminated the Alert.

3.0 PERSONNEL AND NUCLEAR PLANT SYSTEMS PERFORMANCE

The AIT assessed the performance of the personnel and the plant systems before, during, and after the event. The findings of the AIT are grouped into three broad categories: Equipment Performance; Procedure Adequacy; and Personnel Performance.

3.1 Equipment Performance

The equipment performed as expected, with the exception of the power supplies to the control room annunciators, the instrument air system, and the Division III EDG. Also, MDS-3 initially failed to close, but it was inspected by the licensee, no problems were found, and it closed successfully on the next attempt.

3.1.1 Power Supplies to Control Room Annunciators

As discussed in Section 2.4.1, control room annunciator power from UPS-1A was from the maintenance supply at the time of the event. Loss of line 5 deenergized the maintenance supply and the power supplies from UPS-1B sustained the load for less than 30 seconds before tripping and deenergizing the control room annunciators. A WR had been initiated on March 9, 1992, with a "C" priority (less than 7 days) to troubleshoot the inability of UPS-1A to transfer, but no work had begun as of March 23, 1992.

Post-event investigation determined that one of the small internal battery packs had failed and, after battery replacement, UPS-1A was able to transfer properly from the maintenance supply. The licensee sent the failed battery to a vendor for a failure analysis. The licensee planned replacement interval for these batteries was 15 months. The failure of one battery after about seven months requires followup.

3.1.2 Instrument Air System

The loss of line 5 deenergized two of the three air compressors and air pressure began to drop. Operators took various actions as valves began to drift to their failed (on loss of air) positions causing, in some cases, system transients. One such transient resulted in the loss of cooling water to the remaining running air compressor which tripped and increased the rate of air pressure loss.

Operators were also concerned about the possibility of leakage through the seals around the reactor vessel and in the main steam lines. The seals are designed not to fail catastrophically on loss of air but do use air pressure to enhance leak tightness. An operator was immediately dispatched to continuously monitor water level in the flooded reactor cavity.

Although there was no evidence of seal leakage during the event, the operators were concerned about possible seal leakage or failure due to loss of air pressure. Operators were also required to take various other actions to mitigate transients caused by loss of air pressure. No backup air supply, such as a diesel air compressor for the system or pressurized bottles for the seals was provided during the refueling outage.

3.1.3 Division III EDG Trip

The Division III EDG started, as designed, due to undervoltage on the Division III bus caused by the loss of line 5. The EDG supplied the bus until it tripped on high jacket water temperature caused by the loss of service water flow following the loss of line 6.

At the time of the event, service water was available to the Division III EDG from service water pumps (SWP) on the Division I bus (SWP-1A) and the Division II bus (SWP-1B). The loss of line 5 deenergized the Division I bus, tripping SWP-1A. The Division I EDG was out of service undergoing planned maintenance so the Division I bus remained deenergized until power was restored to it from an offsite source. Service water continued to be supplied to the running Division III EDG from SWP-1B, which was powered from the Division II bus being energized from line 6.

The service water supply valves to the Division III EDG automatically shut on low water pressure but require operator action to open. This automatic closure feature is blocked for the first minute of Division III EDG operation. The time delay is sufficient for the Division I and Division II EDGs, if started simultaneously with the Division III EDG, to come up to speed and sequence the service water pumps onto the buses and restore system pressure. The design, therefore, assumed the simultaneous loss of offsite power (LOOP) and start of all EDGs.

The March 23, 1992 event, involved a sequential loss of offsite power with 18 minutes between the loss of line 5 and line 6. The trip of line 6 deenergized the Division II bus, tripping the remaining running service water pump (SWP-1B). The Division II EDG successfully started automatically, reenergized the Division II bus, and the safety-related components (including SWP-1B) on the bus were reenergized in the proper sequence. The interruption in service water pressure and

flow caused the closure of the Division II service water supply valve to the running Division III EDG since the one minute duration closure block on the valve had begun 18 minutes earlier when line 5 was lost. The Division III EDG tripped due to loss of cooling water about seven minutes later.

The trip of the Division III EDG demonstrated a previously not recognized vulnerability to a sequential LOOP. The interrelationship in the controls logic of the three EDGs would lead to the loss of cooling water to the Division III EDG in the following generalized scenario:

- Loss of the offsite line supplying Division III and Division I (or Division II) buses, coincident with main generator trip (or bus transfer not available);

- The Division III EDG starts successfully but the other EDG fails (or is not in service);

- Loss of remaining offsite line 15 seconds or more later.

The possibility that a sequential LOOP may be more limiting than a simultaneous LOOP is a potential generic issue. The above scenario also indicates the need to reassess the NMP-2 emergency core cooling system (ECCS) with respect to this previously not recognized vulnerability.

3.2 Procedure Adequacy

In general, the licensee's procedures were adequate, and they provided direction to control the event. However, the plant electrical procedures were cumbersome and in some cases contained generic information in lieu of specific details. An example is, the system operating procedures for the 115 kV Switchyard, 13.8 kV/4.16 kV/600V, and Emergency A.C. Distribution systems all contain the same generic information for a "Loss of Bus" event. This type of procedure format does not ensure a consistent operational practice between all operating crews.

The overhead alarm response procedure for the tripped backup overcurrent relay No. 852426, "Aux Boiler Transformer BU LKO Relay Trip" did not contain the relay impact on 115 kV line 5 or 6.

Procedure N2-OP-72, "Standby and Emergency A.C. Distribution," was the only procedure that specifically stated to reset lockout relays (86 overcurrent devices) prior to energization of the 4.16 kV 1E busses. Operating procedures N2-OP-70, "Station Electrical Feed and 115 kV Switchyard," and N2-OP-71, "13.8 kV/4160V/600V A.C. Power Distribution," did not direct the operators to reset tripped relays prior to energizing electrical busses or distribution lines.

The operating procedure used to cross-tie 115 kV Line 6 to reserve station service transformer 1A, N2-OP-70 section H.5.0, did not reference the protective interlock trip from the auxiliary boiler transformer regular or backup overcurrent relays (86 devices).

The procedure used to return 115 kV Line 5 to service is an example of a cumbersome procedure. Procedure N2-OP-70 section 7.0 provides direction to first, go to procedure N2-OP-71 section H, and perform steps 1.0.a through 1.0.n or H.5.0 as applicable. The operator returns back to procedure N2-OP-70 for nine steps. After completing the nine steps, procedure N2-OP-70 directs the operator back to procedure N2-OP-71 section H.6.0. The first step in N2-OP-71 section 6.0.a. refers the operator back into procedure N2-OP-70 section E. N2-OP-70 section E.2.0 and 3.0 provide direction to energize reserve station service transformer 1A. When the reserve station service transformer 1A is energized, the operator returns to procedure N2-OP-71 section 6.0.b. to complete the restoration of power to the 13.8 kV and 4.16 kV buses.

3.3 Personnel Performance

3.3.1 Auxiliary Boilers Relay Calibration Work Package

The work package prepared for the calibration of the auxiliary boiler backup overcurrent protection relays was not adequate. The package did not contain all the drawings needed to understand the effects should any of the relays be actuated. The plant impact assessment, which was part of the work package, did not address the impact of inadvertent relay actuation during the work. Work package review activities, which were corrective actions following the Nine Mile Point Unit 1 loss of ultimate heat sink (see NRC Inspection Report 50-220/92-80), did not identify and correct these deficiencies.

Similar problems were found in other relay work packages, but a review of a sample of non-relay work packages did not identify similar deficiencies.

3.3.2 Meter and Test Technicians

The performance of the meter and test personnel during the event was weak.

The technician working at the relay and replacing the cover did not know the effects of inadvertent relay actuation. The technician performance error during cover replacement was inadvertent and, due in part, to human factor problems. Only a small positioning error was necessary to bump the contacts closed and the technician had to lean over in a kneeling position to replace the cover on the relay which was just a few inches from floor level.

The prompt, forthright disclosure of the performance error helped control room operators understand the cause of the loss of line 5. Due to the concurrent loss of control room annunciators, operators were not able to identify immediately the cause of the event and thought initially that it had originated offsite.

The ASSS asked the meter and test personnel, who had come to the control room to explain the trip, if there was any problem in closing MDS-20 preparatory to using power from line 6 to reenergize lost buses. The meter and test personnel inaccurately stated that there was no problem in the proposed course of action. Closure of MDS-20 caused the trip of R-60 and the loss of line 6 (LOOP), since the initial relay trip had not been reset.

3.3.3 Control Room Operators

The licensed operators' response to the loss of 115 kV offsite electrical power was good. The shift correctly classified the loss of control room annunciators as an Alert. The operators made a reasonable decision to restore electrical power to the Division I distribution system from 115 kV line 6. The factors affecting their decision were: 1) continued loss of all control room overhead annunciators; 2) dropping air pressure resulting in the possibility of leaking main steam line plug and refuel cavity seals, which could have led to a loss of water in the reactor cavity and spent fuel pool; 3) known delays, of at least one half hour, to restore the normal electrical power to reserve station service transformer "A" from the offsite 115 kV switchyard; 4) the auxiliary boiler transformer was electrically isolated (the overcurrent relay that was inadvertently tripped was a protective device for the auxiliary boiler transformer); 5) when asked by the assistant station shift supervisor (ASSS), the relay personnel informed the operators that

there was no threat to 115 kV line 6 if they used Line 6 to restore power to reserve station service transformer 1A; 6) the relay senior tester had ten years experience at NMP-2, was familiar with the relay protective trips, and was the technical expert in the area of relay knowledge.

The restoration of power was good even though the electrical system operating procedures were cumbersome. The procedure problems details are discussed in section 3.2.

The station shift supervisor (SSS) exhibited good command and control while conducting the plant restoration. Specifically, the restoration of the residual heat removal (RHR) shutdown cooling system was timely.

The operators' decisions for plant restoration were influenced by some circumstances beyond their control. Examples are listed below.

- The restoration of the 115 KV electrical power required a traveling operator, based out of Fulton, New York.

- The overhead annunciator alarms were lost 20 seconds after the loss of 115 kV line 5.

- The plant did not have a backup contingency for the loss of instrument and service air.

4.0 GENERIC IMPLICATIONS OF THIS EVENT

The AIT reviewed this event for generic implications and identified one item that has potential generic implications. The trip of the Division III EDG (see Section 3.1.3) demonstrated that a sequential LOOP might be more limiting, in some cases, than an instantaneous LOOP.

5.0 LICENSEE CORRECTIVE ACTIONS

5.1 Immediate Corrective Actions

1. Immediately following the event, the plant manager issued a stop work order with respect to all relay work.

2. A review of all relay work requests was ordered.

3. An assessment organization was formed to investigate the circumstances leading to this event, plant response and personnel action before, during, and after the transient, and the root cause of the event. These actions included assessing possible modifications to prevent recurrence of the Division III EDG trip.

5.2 Short Term and Long Term Corrective Actions

In addition to the immediate actions described in Section 5.1, the licensee implemented or announced planned corrective actions to address weaknesses and concerns identified following the event. These short term and long term corrective actions were in the following areas: work control, meter and test technician job performance, operator performance, Division III EDG reliability, and control room annunciator power supply reliability.

The licensee was requested to document and discuss these short term and long term corrective actions by letter to the NRC within 30 days of receipt of this report. The effectiveness of the corrective actions will be reviewed as part of the routine inspection program.

6.0 CONCLUSIONS

The AIT concluded that the cause of the initiating event (relay trip of line 5) was an inadvertent technician performance error caused, in part, by human factors problems.

The loss of control room annunciators was caused due to a continued vulnerability in the current design during shutdown or transient conditions. Delays in addressing a known problem in one source of power to the annunciators (UPS-1A) indicates a need for review of oversight of prioritization and scheduling.

The AIT identified the following weaknesses in management support of operations:

1) Acceptance of delays in operation of offsite power supply breakers inherent in the use of a travelling operator based in Fulton, New York.

2) Absence of a backup air supply during the refueling outage with air pressure being used in reactor vessel and main steam line seals.

3) Acceptance of cumbersome, generic procedures which require operators to use concurrently several procedures during an event such as a LOOP.

The Division III EDG was not required to mitigate this event, but the trip of the EDG demonstrated a generic and previously not recognized vulnerability (see Section 3.1.3) that requires followup.

The consequences of this event were minimal because the reactor core and the reactor coolant were unaffected by this event, there was no equipment or structural damage, and no radiation was released.

7.0 MANAGEMENT MEETINGS

The licensee management was informed of the scope of this AIT during an entrance meeting on Tuesday, March 24, 1992. The licensee management was briefed of the inspection observations routinely and at the conclusion of onsite review on Saturday, March 28, 1992.

A public exit meeting was conducted on April 1, 1992 at 1:00 p.m. at the licensee's training facilities with licensee representatives identified in Appendix C to discuss the preliminary inspection findings. The licensee acknowledged the inspection findings and provided the results of their assessment of the event and the short and long term corrective actions for both units.

TABLE 1

CHRONOLOGY OF EVENTS

3/09/92

UPS 1A transferred automatically to maintenance power supply due to voltage fluctuation associated with energization of main turbine EHC system.

Attempts to manually transfer UPS 1A back to its normal source were unsuccessful. Work Request (WR) 201538 was initiated with a seven-day priority to resolve problem.

3/20/92

Meter and test technicians began calibrating relays using electrical preventive maintenance procedure (No. S-EPM-GEN-2Y070)

3/23/92

Initial Plant Conditions:

The plant was in the refueling mode with the reactor vessel head removed and the reactor cavity flooded to normal refuel level. Approximately on-third of the core had been transferred to the spent fuel pool, but no refueling activities were in progress. Emergency diesel generator (EDG-EGS1) and associated ECCS systems were out-of-service for planned maintenance. All other equipment was in a normal shutdown lineup for existing plant conditions. The electrical lineup is shown on Figure 2.

1008 Auxiliary boiler overcurrent protection relay actuated during cover replacement by technician following calibration. At this time offsite 115 kV power line 5 tripped which deenergized UPS-1A and the Division I and the Division III safety-related 4 kV boards. Loss of the 4 kV boards stopped the Division I service water pump (SWP-1A) and instrument air compressor (C1A).

After about 10 seconds, EDG-EG2 successfully completed an automatic start and restored power to the Division III 4 kV board. After about 20 seconds, control room annunciators were deenergized due to inability of the remaining power supply (UPS-1B) to sustain the load.

1009 Operator sent to refuel floor, confirmed no drop in water level, established communications with the control room, and remained there to monitor level.

1016 Licensee declared Alert in accordance with the emergency plan due to loss of control room annunciators.

1018 The remaining running air compressor (C1B) tripped due to loss of cooling water.

1026 Operators closed MDS-20 in attempt to reenergize UPS-1A and the Division I 4 kV board from offsite 115 kV power line 6. This resulted in loss of line 6 due to failure to first reset relay which initiated the original trip of line 5. At this time, the site had lost all offsite power (LOOP).

Loss of line 6 deenergized the Division II 4 kV board which tripped SWP-1B (the only remaining service water pump) and RHS-P1B (the pump providing shutdown cooling). About 10 seconds later, EGS-EG3 successfully completed on automatic start and restored power to the Division II 4 kV boards.

1027 SWP-1B automatically restarted per design, restoring service water for Division II loads.

1028 RHS-P1B restarted (shutdown cooling restored).

1033 EDG-EG2 tripped on high jacket water temperature.

1044 Operations personnel reset auxiliary boiler overcurrent protection relay which had initiated trip of line 5 and, later, line 6.

1046 Offsite power available to Division II 4 kV board (powered at this time from the running EDG-EG3).

1055 Initial attempts to restore power to UPS-1A, the Division I 4 kV board and the Division III 4 kV board were not successful (MDS-3 would not close).

1131 UPS-1A restored which restored control room annunciators.

1136 Instrument air pressure restored to normal.

1144 Division I 4 kV board reenergized (via line 6 through the auxiliary boiler transformer).

1221 Division III 4 kV board reenergized (via line 6 through RTX-1B).

1245 EDG-EG3 removed from Division II 4 kV board (powered at this time from line 6).

1307 SWP-P1A restarted.

1317 Alert terminated.

APPENDIX A

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

MAR 2 4 1992

MEMORANDUM FOR: Marvin W. Hodges, Director
Division of Reactor Safety

Charles W. Hehl, Director
Division of Reactor Projects

FROM: Thomas T. Martin
Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM (AIT) CHARTER - LOSS OF OFFSITE POWER WITH COMPLICATIONS

You are directed to perform an Augmented Inspection Team (AIT) review of the causes, safety implications, and associated licensee actions which led to the inadvertent loss of offsite power and control room annunciations at Nine Mile Point Station Unit 2. The basis of the NRC concern is the management control of maintenance activities that allowed the event to occur. The inspection shall be conducted in accordance with NRC Manual Chapter 0513, Part III, Inspection Procedure 93800, Regional Instruction 1010.1 and additional instructions in this memorandum.

DRS is assigned responsibility for the overall conduct of this inspection. DRP is assigned responsibility for resident inspector and clerical support and coordination with other NRC offices. J. Beall is designated as the onsite Team Leader. Team composition is described at the end of this memorandum. Team members are assigned to this task until the report is completed and will report to Mr. Beall.

OBJECTIVE

The general objectives of this AIT are to:

a. Conduct a timely, thorough, and systematic review of the circumstances surrounding the event, including the sequence of events that led to and followed the March 23, 1992, loss of offsite power and control room annunciator panels;

b. Collect, analyze, and document relevant data and factual information to determine the causes, conditions, and circumstances pertaining to the event, including the response to the event by the licensee's operating staff;

c. Assess the safety significance of the event and communicate to Regional and Headquarters management the facts and safety concerns related to the problems identified; and

d. Evaluate the appropriateness of the licensee's review of and response to the event and implemented corrective actions.

SCOPE OF THE INSPECTION

The AIT should identify and document the relevant facts and determine the probable causes of the event. It should also critically examine the licensee's response to the event. The Team Leader shall develop and implement a specific, detailed plan addressing this event.

The AIT should:

a. Develop a detailed chronology of the event;

b. Determine the root causes of the event and document equipment problems, failures, and/or personnel errors which directly or indirectly contributed to the event.

   Potential items to be considered:

   - Operator actions during and following the event.
   - Outage planning including adherence to controls and schedule to minimize shutdown risk.
   - Management and administrative controls in place before, during and following the event.
   - Coordination of maintenance activities before and during the event, including work planning and control.
   - Assess the performance of the UPS system during the event.
   - Sensitivity to plant conditions.
   - Communications among plant personnel and with/within control room.

c. Determine the expected response of the plant and compare it to the actual response. Assess plant response including but not limited to the following:

- EDG III tripping
- Cause of delays in restoring offsite line five
- Cause of the reactor building sump alarms

d. Assess the adequacy of the responses of the operations and technical support staffs to the event and the initial licensee analysis. Assess licensee actions in restoring power.

e. Determine the management response including the scope and quality of short-term actions and gather information related to the long-term actions intended to prevent recurrence of this event, including internal and external communications/dissemination of licensee-identified concerns and corrective actions.

f. Determine the relationship of previous events or precursors, including site-related, if any, to this event.

g. Determine the potential generic implications of this event, such as recommend lessons learned, and the necessity for generic industry communications.

SCHEDULE

The AIT shall be dispatched to Nine Mile Point Station Unit 2 so as to arrive and commence the inspection on March 24, 1992. A written report on this inspection shall be provided to me within three weeks of completion of the onsite inspection.

TEAM COMPOSITION

The assigned Team members are as follows:

Team Manager:	M. Hodges, DRS
Onsite Team Leader:	J. Beall, DRS
Onsite Team Members:	S. Hansell, DRS
	D. Brinkman, NRR
	J. Ibarra, AEOD

Thomas T. Martin
Regional Administrator

cc:
W. Kane, DRA
W. Hehl, DRP
C. Cowgill, DRP
L. Nicholson, DRP
Team Members
R. Lobel, OEDO
J. Calvo, NRR
R. Capra, NRR
K. Abraham, PAO
L. Spessard, AEOD
E. Rossi, NRR
W. Lanning, DRS
J. Durr, DRS
L. Bettenhausen, DRS
SRI NMP-1

APPENDIX B

PERSONS CONTACTED

Niagara Mohawk Power Corporation

Name	Position
* C. Beckham	Manager, QA Operations, Unit 2
J. Burton	Manager, QA Operations, Unit 1
T. Collins	Technician, Meter and Test
M. Conway	Station Shift Supervisor, Unit 2
R. Crandall	System Engineer
* K. Dahlberg	Unit 1 Plant Manager
J. Darling	Technician, Meter and Test
A. DeGracia	Operations Manager, Unit 2
S. Doty	General Supervisor, Electrical Maintenance, Unit 2
E. Dragomer	Station Shift Supervisor, Unit 2
* J. Endries	President, Niagara Mohawk Corporation
M. Eron	Assistant Station Shift Supervisor, Unit 2
C. Gerberich	Control Room Operator, Unit 2
D. Hanczyk	Control Room Operator, Unit 2
* D. Hosmer	Unit 2 Manager Outage/Wk Control
A. Julka	Supervisor, Electrical Design, Unit 2
D. Kinney	Operations Planner
H. Lockwood	Technician, Meter and Test
D. Lomber	Control Room Operator, Unit 2
* M. McCormick, Jr.	Unit 2 Plant Manager
R. Menikheim	Supervisor, Meter and Test
J. Pavel	Site Licensing Engineer
F. Peters	Technician, Meter and Test
L. Pisano	Unit 1 Outage Manager
R. Reynolds	Control Room Operator, Unit 2
R. Slade	General Supervisor, Training Operations, Unit 2
J. Spadafore	Program Director, ISEG
* R. Sylvia	Executive V. P. - Nuclear
* C. Terry	V. P. - Nuclear Engineering
T. Tomlinson	Supervisor, Reactor Engineering, Unit 2
D. White	Assistant to the Plant Manager, Unit 2
* S. Wilczek, Jr.	V. P. - Nuclear Support

U.S. Nuclear Regulatory Commission

	R. Capra	Project Director, NRR
	C. Cowgill	Branch Chief, RI
*	M. Hodges	Director, DRS
*	L. Nicholson	Section Chief, DRP
*	W. Schmidt	Senior Resident Inspector

* Denotes those present at the exit meeting on April 1, 1992, attended by the public and news media. The team also held discussions with other licensee management, operations, maintenance, engineering and quality assurance personnel.

APPENDIX C

DOCUMENTS REVIEWED

1. Chief Shift Operator and Station Shift Supervisor logs for March 23, 1992.

2. Copies of written statements provided by personnel involved in the event.

3. Computer alarm logs for 1008 hours - 1308 hours on 03/23/92

4. Administrative Procedure AP-5.2.5, Rev.01, Work In Progress (WIP)

5. Administrative Procedure AP-5.4, Rev.04, Conduct of Maintenance

6. Administrative Procedure AP-5.4.2, Rev. 02, Troubleshooting

7. Administrative Procedure AP-5.5, Rev. 02, Work Control

8. Administrative Procedure AP-5.5.1, Rev. 06, Work Request

9. Nuclear Division Interfacing Procedure NIP-ECA-01, Rev. 03, Deviation Event Report

10. Generation Administrative Procedure GAP-OPS-01, Rev. 00, Administration of Operations

11. Electrical Preventive Maintenance Procedure S-EPM-GEN-2Y070, Revision 1, dated 05/17/88; with Data Sheet (Attachment 10.3) for Equipment Piece No. 2 ABS-X1, dated 03/23/92; Test Results Information Sheet for 2ABS-X1, dated 03/23/92; and Work In Progress Data Sheet for 2 ABS-X1, dated 03/20/92.

12. Work Control Monitoring Program Plan for Nine Mile Point Unit One and Unit Two, . Revision O, March 17, 1992.

13. Nine Mile Point Unit 2 Outage/Work Control Department Instruction Shutdown Safety, Revision 00 (draft).

14. Administrative Procedure AP-5.2.3, Revision 03 "Preventive Maintenance Program.

15. Surveillance Reports 92-15000 dated 03/12/92 and 92-15001 dated 03/20/92.

16. Surveillance Reports 92-23001 dated 03/12/92 and 92-23002 dated 03/20/92.

17. Deviation/Event Reports 1-92-Q-0770, 1-92-Q-0771, 1-92-Q-0772, 1-92-Q-0786, 1-92-Q-0787, 1-92-Q-0818, 1-92-Q-0819, 2-92-Q-0949, 2-92-Q-0950, 1-92-Q-0812, 2-92-Q-0802.

18. Training Plans for March 9, 1992 Site Management Meeting for training on the Work Control Process Monitoring Program.

19. Work In Progress Data Sheets 2TMI-TE157, 2TMB-T1CIA, 2TMI-TE153, Remote Shutdown 2CES*PNL405, 2FNR-CRN1, 2SFC-STR5, 2MSS*V1A, 2CND-IPNL287, 2TMI-SE133, 2HDL-LT22A, 2TMI-TE152, Remote Shutdown 2CES*PNL405.

20. Work Requests Nos. 190344, 199188, 200401, 201294, 201292, 201538, 200568, 199163, 184946, 177320, 195594, 200150, 200347, 198008, 200523, 200140, 193168, 177162, and 200182.

21. Operating Procedure N2-OP-70, Rev. 2, Station Electrical Feed and 115KV Switchyard

22. Operating Procedure N2-OP-71, Rev. 3, 13.8KV/4160V/600V A.C. Distribution System

23. Operating Procedure N2-OP-72, Rev. 4, Standby and Emergency A.C. Distribution System

24. NMP-2 Training Response to the NMP-2 Alert on March 23, 1992

25. Alarm Response Procedures (ARP)
    - 852426 Aux Boiler Transformer BU LKO Relay Trip
    - 852434 Reserve Station Transformer 1A Loss of Voltage
    - 852431 Motor Operated Circuit Switcher 2YUC-MDS5 Open
    - 852533 Aux Boiler Transformer Loss of Voltage
    - 852453 Aux Boiler Transformer Backup Transfer Trip

26. Drawing 12177-ESK-8YUC05, 115KV Transfer Trip 2nd Alternate, Sh. 1 and 2

27. Drawing 12177-ESK-8YUC03, 115KV Ckt Switcher 2YUC-MDS5 Cont

28. Drawing 12177-ESK-8YUC04, 115KV Transfer Trip 1st Alternate, Sh. 1 and 2

29. Drawing 12177-ESK-8SPR14, XFMR 2ABS-X1 RLY

30. Drawing 12177-ESK-8SPR10, XFMR 2ABS-X1 Backup Prot

31. Drawing 12177-ESK-8SPR12, XFMR 2ABS-X1 Pri Prot

32. Drawing 12177-ESK-8SPR11, XFMR 2ABS-X1 Fault Press Prot

33. Drawing 12177-EE-1EA-10, 115KV Swyd One Line Diagram

34. Drawing 12177-ESK-8NNS07, XFMR 2ABS-X1 4KV Winding Prot

35. Drawing 12177-ESK-5NPS07, BUS 2NPS-SWG002 Supply ACB2-5

36. Drawing 12177-ESK-5NNS16, BUS 2NNS-SWG018 Supply CB18-2

37. Drawing LSK-24-8.2N, Normal Station Service (13.8 KV) Breaker Controls

38. Drawing LSK-24-5.3A, Auxiliary Boiler Transfer Protection

39. Drawing LSK-24-7.2C, 115KV Motor Operated Circuit-Switcher Control

40. Drawing LSK-24-5.2C, 115KV Line Protection Transfer Trip

41. Drawing LSK-24-8.60, 4.16KV Normal Station Service Breaker Control

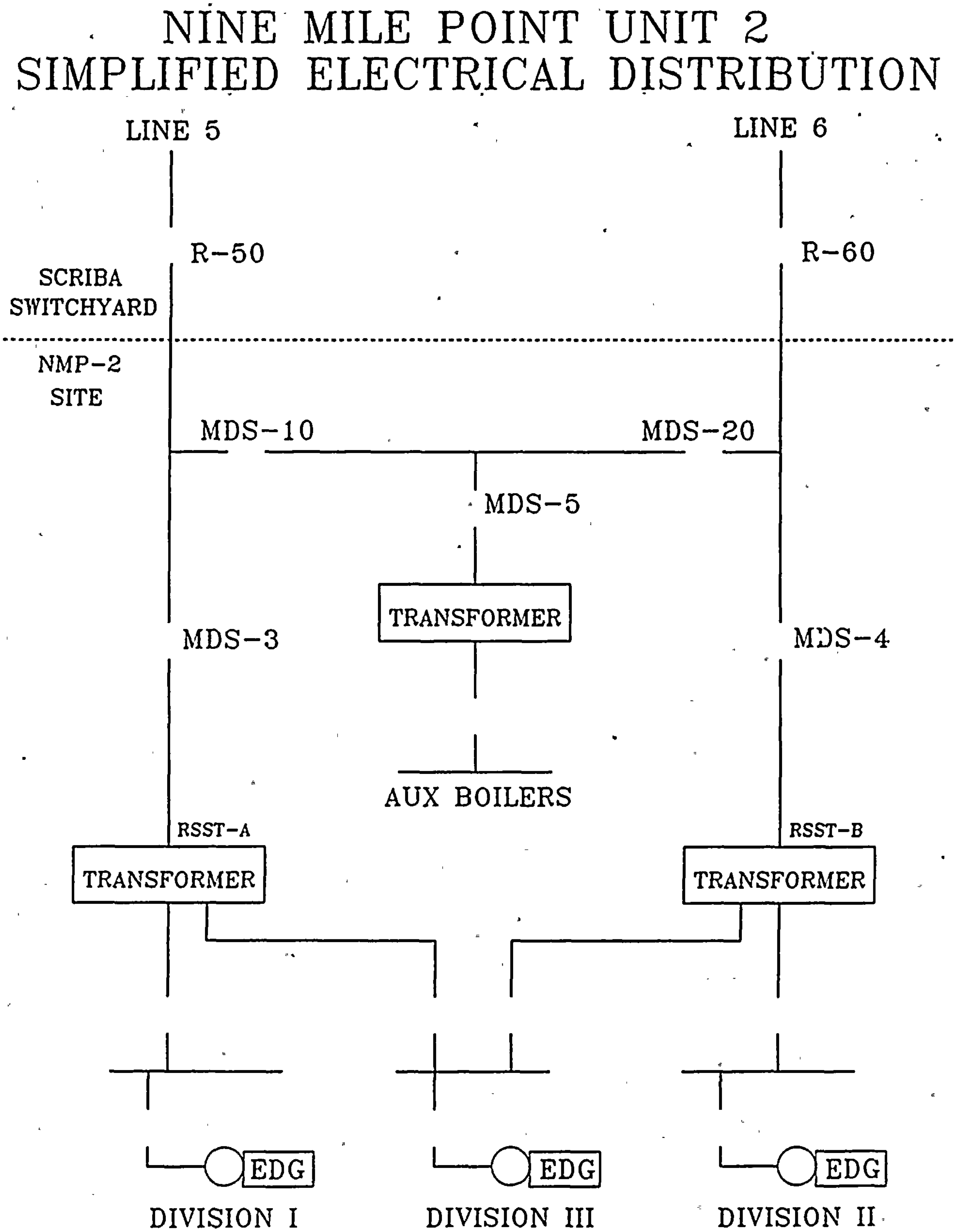
42. Nine Mile Point Nuclear Station Unit 2, One Line Diagram, 115KV Switchyard Offsite Power Sources Backup Protection, Sheets 1 and 2, Provided on March 26, 1992

43. Nine Mile Point Nuclear Station Unit 2, One Line Diagram, Present Arrangement UPS1A & 1B Power Feeds to NSSS Annunciator Panel 2CEC-PNL630, Provided on March 26, 1992

44. Nine Mile Point Nuclear Station Unit 2, One Line Diagram, Present Arrangement UPS1A & 1B Power Feeds to BOP Annunciator Panels 2CEC-PNL858 & 2CEC-PNL833, Provided on March 26, 1992

45. Exide Electronic Drawing C1061373, Logic Supply and Relay Panel UPS MKII-A

FIGURE 1


NINE MILE POINT UNIT 2
SIMPLIFIED ELECTRICAL DISTRIBUTION
LINE 5
LINE 6
R-50
R-60
SCRIBA
SWITCHYARD
NMP-2
SITE
MDS-10
MDS-20
MDS-5
TRANSFORMER
MDS-3
MDS-4
AUX BOILERS
RSST-A
RSST-B
TRANSFORMER
TRANSFORMER
EDG
EDG
EDG
DIVISION I
DIVISION III
DIVISION II