SAFETY ASSESSMENT REPORT

OF

8/13/91 SITE AREA EMERGENCY EVENT-NINE MILE POINT UNIT 2

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LIST OF ACRONYMS

ADS - Automatic Depressurization System
APRM - Average Power Range Monitor
ARI - Alternate Rod Insertion
ASME - American Society of Mechanical Engineers
ATWS - Anticipated Transient Without Scram

BOP - Balance of Plant
BWROG - Boiling Water Reactor Owners Group

CAN - Community Alert Network
CCP - Reactor Building Closed Loop Cooling
CPR - Critical Power Ratio
CRD - Control Rod Drive
CST - Condensate Storage Tank

DBA - Design Basis Accident
DEC - Department of Environmental Conservation
DRMS - Digital Radiation Monitoring System

ECCS - Emergency Core Cooling System
ENS - Emergency Notification System
EOC RPT - End of Cycle Recirculation Pump Trip
EOF - Emergency Operations Facility
EOP - Emergency Operating Procedure
EPG - Emergency Procedure Guidelines
EPP - Emergency Plan Implementing Procedure
EPRI - Electric Power Research Institute
EQEDC - Equipment Qualification Environmental Design Criteria
ERF - Radwaste Computer (SPDS Computer)
ERF's - Emergency Response Facilities
ERO - Emergency Response Organization

GEMS - Gaseous Effluent Monitoring System
GETARS - General Electric Transient Analysis Recorder System

H_2/O_2 - Hydrogen/Oxygen
HPCS - High Pressure Core Spray System
HRA - Human Reliability Analysis
HWC - Hydrogen Water Chemistry

IGA - Intergranular Attack
IGSCC - Intergranular Stress Corrosion Cracking
IPE - Individual Plant Evaluation

JAF - James A. FitzPatrick Nuclear Station

LCO - Limiting Condition for Operation
LOCA - Loss of Coolant Accident
LPCI - Low Pressure Coolant Injection
LPRM - Local Power Range Monitor

MCPR - Minimum Critical Power Ratio
MSIV - Main Steam Isolation Valve

NMPC - Niagara Mohawk Power Corporation
NMP1 - Nine Mile Point Unit 1
NMP2 - Nine Mile Point Unit 2
NRC - Nuclear Regulatory Commission

OSC - Operations Support Center

PAM - Post Accident Monitoring
ppb - part per billion

RBM - Rod Block Monitor
RCIC - Reactor Core Isolation Cooling
RCS - Recirculation System
RHR - Residual Heat Removal
RMCS - Reactor Manual Control System
RPS - Reactor Protection System
RPV - Reactor Pressure Vessel
RRCS - Redundant Reactivity Control System
RSCM - RHR Shutdown Cooling Mode
RSCS - Rod Sequence Control System
RSS - Remote Shutdown System
RWCU - Reactor Water Cleanup System
RWE - Rod Withdrawal Error
RWM - Rod Worth Minimizer

SAE - Site Area Emergency
SDV - Scram Discharge Volume
SED - Site Emergency Director
SER - Safety Evaluation Report
SLCS - Standby Liquid Control System
SPDS - Safety Parameter Display System
SRV - Safety Relief Valve
SSER - Supplemental Safety Evaluation Report
SSS - Station Shift Supervisor

TCV - Turbine Control Valve
TS - Technical Specifications
TSC - Technical Support Center
TSV - Turbine Stop Valve

μS/cm - micro Sievert per centimeter
UPS - Uninterruptible Power Supply
USAR - Updated Safety Analysis Report

EXECUTIVE SUMMARY

In response to an electrical transient, Nine Mile Point Unit 2 was safely and effectively shutdown and brought to a cold shutdown condition. Overall, the response of the facility was well within the scope of the safety evaluation of the unit as discussed in the USAR (Updated Safety Analysis Report). The operator, operating staff, and emergency response organization acted in accordance with procedures, professionally, and were well trained to handle the situation as it developed. As discussed herein, at no time during this event was there any release of radioactive material nor was the health and safety of the public affected. As a result of a review and evaluation of this event, recommendations are proposed which address equipment availability and reliability.

INTRODUCTION AND CONCLUSIONS

SCOPE

This Safety Assessment Report provides a safety review of the Site Emergency Event of 8/13/91 at Nine Mile Point Unit 2 to evaluate the response of plant equipment and human factor issues. This Safety Assessment Report does not evaluate:

1) Root cause of the failure of Phase B Main Transformer 2MTX-XM1B, (Reference: "2MTX-XM1B Failure");

2) Root cause of the failure of Normal Uninterruptible Power Supplies, (Reference: "Root Cause Report for the Exide UPS 1A, B, C, D, G Trip Event of August 13, 1991");

3) Emergency Plan Response, (Reference: "Niagara Mohawk Power Corporation Review of Emergency Preparedness Effectiveness During the Site Area Emergency at Nine Mile Point Unit 2 on August 13, 1991");

4) Reactor Water Chemistry excursion, (Reference: "Evaluation of Water Chemistry Excursion at Nine Mile Point Unit 2 August 13, 1991" prepared by Structural Integrity Associates).

These items including consequential actions are evaluated in the separate reports referenced above.

The assessment described within this report was the result of a detailed review of plant safety systems response, the effect of non-safety systems on the plant's response, and of operator and plant staff activities during the event.

OBJECTIVE

The objective of this safety assessment report is to provide a description and assessment of the physical plant and operator response during the Site Area Emergency at Nine Mile Point Unit 2. The purpose is to assure that the background of this event, the conditions (prior to, during and after) are well understood, and that the analysis of conclusions drawn provide an accurate picture of the event. Finally, recommendations are provided which ensure that a similar circumstance cannot occur.

ASSESSMENT ABSTRACT

EVENT

On August 13, 1991 at 0548 hours, Nine Mile Point Unit 2 (NMP2) experienced a failure of the Phase B main transformer and a subsequent failure of the normal uninterruptible power supplies (UPS), 2VBB-UPS1A-1D and 1G. This incident resulted in a plant transient and a loss of non-safety related control room indication and panel annunciators. These conditions mandated entry into a site area emergency classification as specified by Emergency Action Procedure S-EAP-2.

ASSESSMENT CONCLUSIONS

As a result of the evaluation presented in subsequent portions of this safety assessment report, the following conclusions can be made:

(1) The plant event did not adversely affect the safe shutdown process as described in USAR Section 7.4.

(2) The occurrence of any plant transient (described in Chapter 15 of the USAR), concurrent with this event, would have been bounded by the Cycle 2 reload analyses, i.e., would not have resulted in fuel failures.

(3) The occurrence of a Design Basis Accident - Loss of Coolant Accident (DBA-LOCA) (described in Chapter 6 of the USAR), concurrent with this event, would have been bounded by the Cycle 2 reload analyses, i.e., would not have resulted in fuel failures.

(4) Operator response and the use of emergency operating procedures resulted in the stabilization of all plant parameters and were effective and appropriate.

(5) During the event, varying reactor pressure vessel (RPV) water levels:

(a) did not result in flooding of the Main Steam Lines,
(b) did not result in initiation of any Emergency Core Cooling systems (ECCS), and
(c) did not uncover the fuel.

Therefore, the RPV water level variations, during this event, did not pose any adverse consequences to fuel rod integrity.

(6) During the event:

(a) None of the ECCS initiated nor were they required to initiate;
(b) All Class 1E safety related buses remained continuously energized from both 115KV offsite power feeds;
(c) None of the three emergency diesel generators started nor were they required to start.

(7) At no time during the event did the malfunction of non-safety related equipment adversely affect the ability of safety related equipment to perform their intended design functions.

(8) A fire, had it occurred during this event, would have been detected and extinguished in a timely manner; therefore, the safe shutdown capability of the plant would have been preserved.

(9) The electrical distribution protective relaying schemes actuated and performed their intended function as designed.

(10) At no time during the event did drywell pressure rise sufficiently to initiate a Primary Containment isolation.

In conclusion, based upon the analysis contained in this report, at no time during this event was public health and safety affected.

BACKGROUND AND DESCRIPTION OF EVENT

On August 13, 1991 at 0548 hours, the Phase B Main Output Transformer at Nine Mile Point Unit 2 (NMP2) failed and the normal UPSs subsequently failed; these circumstances resulted in a reactor scram and a loss of control room annunciators and non-safety related indication. These conditions mandated a declaration of a Site Area Emergency classification as specified by Emergency Action Procedure S-EAP-2. (S-EAP-2 is based upon Nuclear Regulatory Commission (NRC) guidance in NUREG-0654.)

Prior to the event, NMP2 was in operational condition 1 (RUN) at 100 % thermal power. Residual Heat Removal (RHR) Low Pressure Coolant Injection (LPCI) - Loops B and C were removed from service for maintenance, prior to the event; however, they were returned to service during the event. Several Limiting Conditions for Operations (LCO's) had been entered, prior to the event, for various process effluent monitors. Aside from the LCO's and the RHR LPCI Loop B&C outage, plant operations (for all purposes) was normal.

The sequence of events for this incident are described in the SCRAM summary 91-01, N2-RAP-6 (Attachment A).

SUMMARY OF CAUSES

The initiating event was the failure of 2MTX-XM1B Phase B Main Output Transformer. Subsequently, the Normal UPSs 2VBB-UPS1A, 1B, 1C, 1D, and 1G failed.

ANALYSIS

Preamble

As a result of the August 13, 1991 electrical transient, and the declaration of a Site Area Emergency at Nine Mile Point Unit 2, the station's response organizations responded and appropriately took the plant to cold shutdown. Operability of the Nine Mile Point Unit 1 (NMP1) and J. A. Fitzpatrick plants were not affected; however, J. A. FitzPatrick declared an Alert in accordance with its emergency plan. Nine Mile Point Unit 1 did not declare an Alert; however, the NMP1 station personnel provided support functions during the event. An NRC Augmented Inspection Team, and subsequently, an Incident Investigation Team arrived at the site. These teams assessed the potential generic safety significance of the multiple electrical component failures and the challenges these failures presented to operator understanding and response to the imposed transient.

This action was taken by the NRC independent of the analysis and assessment performed by Niagara Mohawk Power Corporation (NMPC).

This section discusses the results of NMPC's assessment of physical plant and human factors issues. Additionally, this section assesses the impacts of the electrical transient and subsequent plant responses on nuclear safety.

EVALUATION OF THE IMPACT OF NON-SAFETY RELATED EQUIPMENT OPERATION/MALFUNCTION ON SAFETY RELATED EQUIPMENT

The performance of non-safety related systems during the event was assessed for system interaction with safety related systems and components. The assessment process involved the following:

(1) The sequence of events, as contained in the scram recovery report for this plant event, was reviewed by various members of the safety assessment group.

(2) The following reports, which were generated as a result of this event, were reviewed by various members of the safety assessment group. These reports are:

(a) N2-RAP-6, "Sequence of Events SCRAM 91-01"
(b) "NMPC Review of Emergency Preparedness Effectiveness During the Site Area Emergency at NMP2 on 8/13/91", version 8/27/91
(c) "Root Cause Evaluation; Preliminary Report; Exide UPS 1A, 1B, 1C, 1D, 1G; Trip Event 8/13/91", version 9/2/91
(d) "Assessment of Operator Response and Training Effectiveness", version 8/27/91
(e) "Electrical Distribution System Evaluation Report of event 8/13/91 - NMP2"
(f) "2MTX XM1B Failure"

(3) The results of items (1) and (2) were evaluated against the groups knowledge of the plant design and licensing bases as well as reviewing pertinent portions of the USAR.

Based on this assessment process, no adverse impacts to safety related systems or functions were identified as a result of the operation or malfunction of non-safety related equipment. Specific evaluations of the performance of selected non-safety related systems are discussed in other sections of this report.

EVALUATION OF PLANT EVENT AGAINST NMP2 LICENSING BASIS FOR PLANT SAFE SHUTDOWN PROCESS

Introduction

Section 7.4 of the USAR describes the safe shutdown process for NMP2. The purpose of this portion of this evaluation is to determine whether the failure of the Phase B Main Output Transformer and the tripping of the normal UPSs (2VBB-UPS1A-1D, 1G) adversely affected the safe shutdown process described in the USAR. The evaluation process compared the USAR discussion of the safe shutdown process with the evolution of the plant event. Each safe shutdown system is individually discussed and the response to the plant event is evaluated. We conclude that, with one minor exception (failure of RCIC to operate smoothly in the auto mode of operation), the plant event did not adversely affect the safe shutdown process as described in the USAR. Operators placed the RCIC system in manual mode of operation and the system performance stabilized.

Summary

USAR Section 7.4 indicates that instrumentation and controls of the following systems can be used for safe shutdown:

(1) Reactor Core Isolation Cooling System (RCIC),
(2) Standby Liquid Control System (SLCS),
(3) RHR Shutdown Cooling Mode (RSCM), and
(4) Remote Shutdown System (RSS).

The sources that supply power to the above safe shutdown systems originate from onsite AC/DC safety-related buses which remained available throughout event. Therefore, the tripping of the normal UPSs (1A-1D,1G) and the failure of the Phase B main output transformer, at no time, adversely affected the safety-related safe shutdown capability of NMP2.

RCIC

In response to the plant event, operators manually initiated RCIC due to lowering RPV level. RPV level was decreasing as a result of a loss of feedwater flow in conjunction with Safety Relief Valve (SRV) and Turbine Bypass Valve operation. RCIC initially experienced flow, speed and pressure oscillations while in the automatic mode of operation. Subsequently, operators placed RCIC in manual mode of operation and the system stabilized. Therefore, the RCIC system oscillations, initially experienced, did not impact the safe shutdown of NMP2; the system stabilized upon operator action which placed RCIC in the manual mode of operation.

After reactor pressure had been sufficiently reduced to allow the use of Residual Heat Removal System (RHR) in the shutdown cooling mode, the use of RCIC was discontinued. However, in the course of taking RCIC out of its RPV cooldown function, operators noted that the RCIC primary containment isolation valve, 2ICS*AOV156, failed to indicate "full closed" in the control room. As a result, the redundant primary containment isolation valve, 2ICS*MOV126, was placed in the closed position and deactivated. In addition, RCIC was declared inoperable due to the deactivated primary containment isolation valve. The inoperability of RCIC did not adversely affect the safe shutdown of NMP2 since RCIC was no longer needed.

Subsequent investigation of 2ICS*AOV156 indicated that this valve had actually reached its full closed position. The lack of full close indication in the control room was attributed to a limit switch which needed readjustment.

Operators also noted that the RCIC injection valve, 2ICS*AOV157, did not indicate "open" in the control room during RCIC operation. However, operators confirmed that 2ICS*AOV157 was actually open by verifying injection flow into the RPV by observing a control room RCIC flow meter. Additionally, operators verified that the RPV level was being adequately maintained by RCIC. Therefore, the lack of full open indication in the control room for 2ICS*AOV157 did not adversely affect the ability of RCIC to perform its safe shutdown function. Investigation of 2ICS*AOV157, subsequent to the event, indicated that the lack of control room indication was due to a broken cam.

SLCS

The control rod position indication in the control room was inoperable due to the tripping of the five normal UPSs. This resulted in the operators not being able to directly determine that all control rods had been fully inserted from the manually initiated SCRAM. However, the APRM back panel meters in the control room were operable and indicated downscale. Due to the lack of control rod indication, the operators entered N2-EOP-C5 "Level/Power Control".

In accordance with the Emergency Operating Procedures (EOPs), the Automatic Depressurization System (ADS) auto-initiation logic was inhibited. This action is consistent with the NMP2 plant specific anticipated transient without scram (ATWS) analysis, documented in General Electric Report NEDE-22013, "Design Analysis and SAR Inputs for ATWS Performance and Standby Liquid Control System, Nine Mile Point Unit 2 Plant"; this report is referenced in USAR section 15.8.4.

After re-energization of normal UPS loads, it was immediately determined that a substantial majority of the control rods were inserted. This was consistent with the APRM back panel meters' downscale indication. Upon further action (resetting the SCRAM), operators determined that all control rods were fully inserted and that an ATWS event had not occurred. However, had an actual ATWS event occurred during this plant transient, the failure of the main output transformer and the normal five UPSs would not have adversely affected the ability of the plant, and the operators to respond consistent with the USAR analysis. This conclusion is supported by the following:

(1) Both trains of Standby Liquid Control (SLCS), as described in USAR section 7.4.1.2, were fully operable prior to and during the event;

(2) The redundant reactivity control system (RRCS), which includes other ATWS mitigation features, was also operable (reference USAR Section 7.6.1.8 for a discussion of RRCS);

(3) Operator actions, based upon an assumed ATWS event, were consistent with both EOP directions and the NMP2 plant specific ATWS analysis.

Hypothetically, even if one were to assume that control rod position indication could not be restored, due to a situation where the UPS power supplies could not be re-energized, this situation is addressed by the EOPs. Specifically, EOPs provide direction for controlling RPV pressure, water level, and criteria for use of standby liquid control system irrespective of knowing that all control rods are inserted. The EOPs instruct the operator to maintain the reactor in a hot shutdown condition until rod position can be verified as fully inserted. Therefore, a failure to restore the UPSs would not have been a concern since the EOPs address such a situation. Also, the various ATWS mitigating design aspects of the plant were fully operable and available to support a plant response to an ATWS event.

RSCM

Shortly after RCIC was started, operators placed 2RHS*P1A in the suppression pool cooling mode of operation. This was done to remove heat buildup in the suppression pool due to RCIC operation and the SRV actuations. This action is consistent with the USAR, Section 7.4.1.4, page 7.4-6.

Operators continued reactor pressure vessel (RPV) cooldown using RCIC until RPV pressure was sufficiently reduced to allow using the condensate system to continue cooldown and for RPV level control. Eventually, RHR pump 2RHS*P1B was placed in the shutdown cooling mode of operation and cooldown continued, using shutdown cooling, until a cold shutdown condition was achieved. This is consistent with the USAR, Section 7.4.1.4, page 7.4-6.

During reactor cooldown, had it been necessary, a redundant safety grade method of supporting reactor cooldown existed if the shutdown cooling mode of operation of RHR became inoperable. The alternate shutdown cooling path uses a sufficient number of ADS SRVs, powered open from safety related buses, to establish a liquid flow path from the RPV to the suppression pool. RHR pumps are then used to direct flow back to the RPV via a LPCI line from the suppression pool through the RHR heat exchanger. This method of alternate shutdown cooling is described in USAR Section 5.4.7.1.1, page 5.4-34. The SRV's, as discussed in USAR Section 1.12, are qualified to support this alternate shutdown cooling mode.

In addition, EOPs also allow the use of the steam condensing mode of RHR and the main steam line drains to provide another alternate shutdown cooling path if necessary.

Therefore, the plant event did not adversely affect the shutdown cooling mode of RHR or the alternate shutdown cooling methods described in the USAR.

RSS

All instrumentation and controls for the remote shutdown system per TS LCO 3.3.7.4 were fully operable. The equipment operated by these controls as indicated on TS Table 3.3.7.4-2 were also fully operable.

CONCLUSION

Based upon the previous evaluation, it can be concluded that the plant event in no way adversely affected the safe shutdown process as described in the USAR.

EVALUATION OF USAR TRANSIENTS AND ACCIDENTS

Introduction

The purpose of this evaluation was to determine if a Chapter 15 USAR transient or a USAR Chapter 6 design basis accident - loss of coolant accident (DBA-LOCA) were to occur, during this plant event, whether the plant response would be bounded by the transient and accident analyses in the USAR. We concluded that in all cases, as analyzed in the USAR, the results would be bounded by the Cycle 2 reload analyses.

Transients

The following is a tabulation of transients analyzed in Chapter 15 of the USAR. The tabulation (USAR Table 15.0-5) identifies the USAR analyzed transient in Chapter 15, the applicable USAR subsection, and the non-safety grade system(s) and/or component(s) that were assumed to operate during a given transient.

NON-SAFETY GRADE SYSTEMS/COMPONENTS ASSUMED IN USAR TRANSIENT ANALYSIS

FSAR Section	Transient	Non-Safety Grade System or Component
MODERATE FREQUENCY EVENTS		
15.1.2	Feedwater Controller Failure with Maximum Demand	Level 8 Turbine and Feedwater Pump Trip, Turbine Bypass, Relief Valves[1]
15.1.3	Pressure Regulator Failure, Open	Relief Valves
15.2.2	Load Rejection	Turbine Bypass, Relief Valves
15.2.3	Turbine Trip	Turbine Bypass, Relief Valves
15.2.4	Closure of all MSIVs	Relief Valves
15.2.5	Loss of Condenser Vacuum	Turbine Bypass, Relief Valves
15.2.6	Loss of AC Power	Turbine Bypass, Relief Valves
15.2.7	Loss of All Feedwater Flow	Recirculation Runback, Relief Valves
15.3.1	Trip of One or Both Recirculation Pumps	Level 8 Turbine and Feedwater Pump Trip, Turbine Bypass, Relief Valves
15.3.2	Recirculation Flow Control Failure with Decreasing Flow	Level 8 Turbine and Feedwater Pump Trip, Turbine Bypass, Relief Valves
15.4.1	Rod Withdrawal Error at Low Power	Rod Sequence Control System (RSCS)
15.4.2	Rod Withdrawal Error at Power	Rod Block Monitor
INFREQUENT EVENTS		
15.2.2	Load Rejection w/o Bypass	Relief Valves
15.2.3	Turbine Trip w/o Bypass	Relief Valves

FSAR Section	Transient	Non-Safety Grade System or Component
LIMITING EVENTS		
15.3.3	Recirculation Pump Seizure	Level 8 Turbine and Feedwater Pump Trip, Turbine Bypass, Relief Valves
15.3.4	Recirculation Pump Shaft Break	Level 8 Turbine and Feedwater Pump Trip, Turbine Bypass, Relief Valves

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(1)"Relief Valves" refers to non-safety grade instrumentation in the relief mode of the SRVs

NOTE: Level 8 Trip itself provides a safety-grade initiation signal and is then isolated from the nonsafety-related controls circuitry to initiate turbine and feedwater pump trip.

Discussion

The two parameters of interest, when analyzing transients in USAR Chapter 15, are delta critical power ratio (CPR) (fuel integrity), and peak RPV pressure (reactor coolant pressure boundary integrity). See USAR section 15.0.6.

Among the non-safety grade systems listed in the tabulation on pages 11 and 12, the failure of the Level 8 (L8 - reactor high water level) trip and the failure of the turbine bypass would affect delta CPR. Loss of the main transformer causes a load rejection and the resulting scram trip of the plant. If the turbine bypass was to fail, the event is equal to the limiting pressurization transient in the current analysis with a resulting delta CPR of 0.20. An assumed coincident or subsequent control failure (e.g. Feedwater control) would have no effect on the fuel thermal margin since that is controlled by the Load Rejection event. The feedwater controller failure, should it also occur, would only require a L8 trip (or manual shutoff) to control the water level in the RPV. In all events, pressure is controlled by the turbine bypass (if available) or the safety relief valves.

Another potential non-safety grade system failure, from the tabulation shown on pages 11 and 12, that could affect Minimum Critical Power Ratio (MCPR) is failure of the Rod Block Monitor (RBM). During the type of event caused by the loss of the main transformer, the load rejection controls the course of the transient. Failure of the RBM has no impact on the resulting fuel thermal margin. Failure of the RBM would only have impact during a Rod Withdrawal Error (RWE) event. The RBM is designed to be single failure proof (USAR Section 15.4.2.2.3) so that complete loss of its function is highly unlikely. Failure of power to the RBM will initiate the rod block; therefore, fuel thermal margin is adequately assured for the RWE event.

The limiting events as defined in USAR Table 15.0-1, which are the Recirculation Pump Seizure and Recirculation Pump Shaft Break, are not typically analyzed for reload cycles in accordance with GESTAR II, since they are considered as accidents and are bounded by the DBA LOCA analyses.

The peak vessel pressures for the analysis of transients, not taking credit for non-safety grade systems and components, are bounded by the peak pressure limit of the over pressure protection analysis described in USAR Section 5.2.

Summary of Transient Evaluation

Based upon the previous evaluation, this report concludes that the failure of the 1B Main Output Transformer and tripping of the normal UPSs (1A-1D, 1G), resulted in a transient like the analyzed Generator Load Rejection. Failure of the turbine bypass is already analyzed (although it did work in this event). If an additional control failure is assumed (e.g. Feedwater controller failure maximum demand), the transient would not result in fuel integrity failure or in RPV pressure exceeding ASME Code criteria. Therefore, the occurrence of any additional plant transient, depicted in USAR Chapter 15, concurrent with this plant event (transient) would be bounded by the Cycle 2 Reload Analyses.

The above analysis is extremely conservative since a feedwater controller failure to maximum demand cannot occur concurrent with its corresponding UPS shutdown; the loss of UPS loads de-energizes feedwater control logic and also causes the reactor level control valves 2FWS-LV10s to lock up. In addition, the UPS shutdown also results in the minimum flow valves for feedwater, condensate booster, and condensate pumps to fail open which trips the feedwater pumps on low suction pressure.

Accident Evaluation and Summary

The USAR Chapter 6 DBA LOCA analysis is based upon the proper functioning of safety related equipment. The Phase B Main Output Transformer and the five normal UPSs (1A-1D and 1G), which became inoperable during the event, do not power any safety related equipment which are required to perform an active safety function. Therefore, a DBA LOCA concurrent with this plant event would be bounded by the Cycle 2 Reload Analyses.

EVALUATION OF THE IMPACT OF THE EVENT ON THE FIRE PROTECTION PROGRAM

This event is not associated with any fire or loss of off-site power which is the design basis for an appendix R fire. Therefore, it did not create any 10CFR50 Appendix-R concern. Although the control room lost fire annunciation, the fire protection system remained operable from the control room and from the local fire panels throughout this event. In addition, a fire patrol was initiated when control room fire detection annunciation was lost. The fire patrol was instituted to monitor the status of local fire protection and detection panels whose annunciation was operable throughout the event. A timely response by plant personnel to an actual fire would have occurred as a result of the surveillance by fire patrols of local fire panels. Therefore, it can be concluded that an actual fire, concurrent with this plant event, would have been detected and extinguished in a timely manner and would not have affected safe shutdown.

ASSESSMENT OF EQUIPMENT ISSUES

Evaluation of Failure of MSIV 6D to Indicate Fully Closed

Upon reaching cold shutdown and closing the Main Steam Isolation Valves (MSIV's), MSIV6D (2MSS*AOV6D) was found to be indicating in mid position. An evaluation of this condition determined that the MSIV's were unaffected by the event because their control circuitry power supplies, 2VBB-UPS3A and 3B, were unaffected by the event. The fact that MSIV6D was found indicating at mid position, although of concern from an equipment standpoint, poses no safety concern because the redundant valve, MSIV7D, (2MSS*AOV7D) was closed. Therefore, primary containment integrity was assured in accordance with the plant licensing and design bases.

Field observation of MSIV6D, subsequent to the event, indicated that the valve had reached its full closed position. The cause of the failure of MSIV6D to indicate full closed can be attributed to a limit switch which needed readjustment.

Evaluation of Reactor Vessel Water Level Excursions

The discussions contained in the reports "Assessment of Operator Response and Training Effectiveness" (Reference 1) and "Scram Summary 91-01" (Attachment A) describe the level variations experienced during the event. As stated in the SCRAM Summary 91-01 N2-RAP-6, the lowest level attained, approximately 124", is above the level 2 setpoint of 108.8". The highest level attained, by extrapolation, was 243" which is approximately 9" below the main steam lines. Therefore, it can be concluded that the various water levels experienced in the RPV during the event:

(1) did not result in flooding of the main steam lines,
(2) did not result in initiation of any ECCS, and
(3) did not uncover the fuel.

In conclusion, the level variations were within design boundaries and were acceptable.

Evaluation of Loss of DIVISION II H_2/O_2 Concentration Recorder

During the event, the Division II H_2/O_2 monitor sample pump was found tripped causing the Division II H_2/O_2 recorder to indicate a high hydrogen (H_2) concentration. This equipment is safety related and receives its power supply from the safety related electrical distribution (1E) buses. The 1E buses were continuously energized from both 115KV offsite power supplies throughout the event. Therefore, it can be concluded that the cause of this failure is unrelated to the electrical transient experienced by the plant.

The loss of the sample pump created a situation of concern regarding the conflicting H_2/O_2 concentration indications. Further evaluation of this condition shows clearly that the pump status was indicated on panel P875 in the control room. Status lamps on P875 readily indicated that the Division II sample pump was not running thereby invalidating indications produced in that division. Actual H_2/O_2 concentrations were available, throughout the event and subsequent cooldown period, on the redundant (Division I) safety-related instruments on control room panel P601. Additionally, indication was restored to Division II once the sample pump was reset.

Only one safety related recorder for H_2/O_2 monitoring is provided, by plant design, which records only Division II H_2/O_2 levels. Since Division II H_2/O_2 monitoring capability was inoperable, the H_2/O_2 concentrations, recorded during the event, were invalid. However, the loss of the recording function of this instrument channel poses no safety concern because:

(1) The ability to status and manually record H_2/O_2 concentration existed with the functioning Division I instrument channel;
(2) Means were readily available to operators in the control room to determine which divisional H_2/O_2 indication was inoperable (by observation of the pump running indication light on panels P873 and P875 in the control room).

Evaluation of Loss of Drywell Cooling

During the event, the drywell cooling fans tripped when the five normal UPSs were lost. Normal (non-safety related) UPSs supply power to an auxiliary relay circuit for the fans. Additionally, as described in USAR Section 9.4.2.5.1, interlocks prevent the fans from starting or trip the units automatically, when any of the associated reactor building closed loop cooling water (CCP) containment isolation valves are closed. The logic circuits interlocking the CCP valve positions with the drywell cooling fan's interlocks are also powered off of non-safety related UPS power. Upon loss of UPS power the fans will automatically receive a trip signal placing them in their fail safe mode. However, loss of the drywell cooling system does not inhibit adequate mixing in the event of a LOCA; adequate atmospheric mixing is accomplished through the utilization of the primary containment spray system, recombiner system, and natural processes (reference USAR Section 6.2.5.2.1).

N2-RAP-6, the SCRAM summary 91-01, states that during the event drywell local temperature reached a high of 165°F (for less than 2 hours) and low of 120°F. This compares to a normal operating range of 70°F minimum and 150°F maximum for the drywell as indicated in the USAR Table 9.4-1, page 2. This temperature maximum (150°F) provides an environment which ensures the optimum performance of equipment within the drywell.

The effect of the increased temperature (165°F) on safety related equipment was evaluated against the Equipment Qualification Environmental Design Criteria (EQEDC). Specifically, the EQEDC was used to identify the environmental conditions for equipment ordered for Nine Mile Point Unit Two. Abnormal events were considered within the EQEDC including a loss of drywell cooling. Drywell cooling failure was assumed to occur 166 times during the 40 year plant life either as a result of power loss or loss of cooling water. The theoretical temperature peak for these events was over 170°F for at least 3 hours. Abnormal events including loss of drywell cooling were considered in the determination of equipment's qualified life. Accordingly, a two hour transient with a 165°F temperature peak has been provided for in the original design/qualified life of equipment installed within the drywell.

The drywell temperature at no time approached the structural design temperature of 293°F or the design environmental temperature of 340°F (Ref. USAR Table 6.2-3). Thus loss of drywell cooling during the event had no safety impact on the primary containment structure or on the safety related equipment contained within. Hypothetically, if drywell cooling could not have been restored prior to exceeding the primary containment design limit, containment spray for both the drywell and the suppression chamber were operable and would have been used for alternate cooling.

Furthermore, as a result of the temperature increase, pressure in the primary containment increased by approximately 0.6 psig over 40 minutes. After restoration of drywell cooling, primary containment pressure was restored to the pre-event value (0.2 psig) in approximately 25 minutes. At no time during the event was an automatic primary containment isolation (1.68 psig) warranted per design nor did it occur. The above primary containment data is based upon a review of strip chart data recorded during the event. See Recommendations, item 3.

Evaluation of Momentary Loss of Normal Reactor Building Lighting

Normal lighting for reactor building general areas, work areas, and electrical equipment areas is provided with low wattage high pressure sodium vapor lights. When a power supply to a continuously energized sodium vapor light is interrupted, the lamp has a cooldown period before a restrike of the lighting can occur. The cooldown period depends upon the rating of the light bulbs.

Normal AC lighting in the reactor building is powered from the plant emergency distribution system using the Reserve Station Service Transformer.

During the event, the plant emergency AC distribution system experienced a brief transient due to the fault on the Phase B Main Output Transformer. As a result of this transient, the reactor building normal lighting, in certain areas, was interrupted for approximately 30 seconds. Normal lighting was automatically restored after the electrical system transient ended. As previously stated, this momentary loss of lighting is due to the inherent design of low wattage high pressure sodium vapor lighting which requires a cooldown period prior to a restrike whenever power in interrupted.

Therefore, this report concludes, that the momentary loss of reactor building normal lighting and its subsequent automatic restoration (as it occurred during the event) was consistent with the description presented in USAR Sections 8.3.1.1.2 and 9.5.3.1. See Recommendations, item 2.

Evaluation of Loss of Plant Communications

The plant communications systems powered by the normal UPSs were temporarily lost during the event. Specifically, the dial telephone system, page/party public address system (GAItronics), and leaky wire radio communications, all powered by normal UPS (reference USAR Section 9.5.2.1), were temporarily lost. However, the external phones on the New York Telephone System and the NRC emergency notification phones were operable. Additionally, the maintenance and calibration communication system and sound powered communication systems were available during the event as well as portable radios without leaky wire assistance.

The loss of the page/party public address system required the control room operators to request the NMP1 Control Room to make the emergency announcements for the site. The notification made from NMP1 did not effectively reach areas within NMP2. Offsite notifications were made with telephones connected to the operable New York Telephone System. The loss of communications systems delayed reports and directions to and from the control room. While restoration of power may have been quicker with normal communications systems in service, operators stated that they still were able to carry out required actions. The portable radio communications system did not appear to be effective without the leaky wire antenna system.

The loss of communications systems has been evaluated as part of the plant design and it functioned properly based on the loss of the normal UPS system.

The failure of the normal UPS system did impact the effectiveness of the control room operators to function as the focal point for making emergency notifications within the plant, directing recovery actions, and receiving damage reports in response to the plant event. Additionally, Unit 1 operators were required to make emergency announcements utilizing the Unit 1 GAItronics system, thus increasing their level of involvement in the Unit 2 event.

As discussed in the NRC's SSER3 section, 9.5.2.1 and USAR section 9.5.2.4, communications to locations outside the main control room is not required to effect a safe shutdown of the plant; therefore, the loss of intra-plant communications during this event is not a safety concern. See Recommendations, item 4.

Evaluation of the loss of Control Room Annunciation, Computer Systems, and Other Monitoring Capabilities

Various plant annunciation, computer systems, and other monitor capabilities and related functions, were rendered inoperable due to the loss of the normal UPSs. Specifically, they were:

1) annunciation in the control room,
2) annunciation in the relay room,
3) annunciation at the remote shutdown panel,
4) process computer,
5) SPDS (Safety Parameter Display System) function (Radwaste Computer)
6) radwaste computer (other functions),
7) GETARS (General Electric Transient Analysis Recorder System),
8) emergency response facility information displays of plant parameters (radwaste computer),
9) fire protection computer,
10) digital radiation monitoring system computer,
11) 3D monicore computer,
12) in-plant oscillograph (see Recommendations, item 1),
13) Rod Position Indication System.

The annunciators, computer systems, and related functions listed above are non-safety related. Their purpose is to augment the ability of the operator to detect situations where various plant parameters exceed normal operating ranges. However, these annunciators and computer systems, while being operator aids, do not form the only basis, upon which, operator action is initiated. The safety-related display instrumentation, which remained operable throughout the event (with the exception of Division II H_2/O_2 indication), is the safety-related basis upon which the reactor operator assesses plant situations. The safety related display instrumentation provides adequate information to allow the reactor operator to perform the necessary manual safety functions during normal operation, transients, and accident conditions. In addition, EOPs are structured in such a manner as to not to rely on plant computer systems or annunciation. The EOPs are structured to rely on the ability of the operator to recognize and assess situations where plant parameters reach manual safety function actuation levels. This assessment ability of the operator is dependent upon the human engineered display of plant safety parameters. These displays are provided to the operator in the control room in the form of the following:

1) recorders,
2) indicating recorders,
3) status lights,
4) running lights, and
5) meters.

These displays, which are adequate in themselves apart from plant annunciation and computers, provides information to the operator to enable him or her to assess the status of safety-related systems and significant plant parameters. Thus the operator is able to perform the required manual safety functions which ensures public health and safety.

While the loss of the non-safety related plant computer systems and annunciation places the operator in a situation where heightened awareness is required, the loss of such devices during the event in themselves does not constitute a safety concern. The safety related displays, in conjunction with safety related controls provides the operator with the capability of achieving safe shutdown. The plant safety related display instrumentation is described in Section 7.5 of the USAR. See Recommendations, item 5.

Evaluation of Electrical Distribution System Performance (Reference 2)

The protective relaying schemes in the switchgear actuated and performed their intended function as designed. Specifically, the transformer and unit differential relays actuated to isolate the fault, the unit protection schemes tripped the turbine, and the 13.8KV normal switchgear buses made a fast transfer to the Reserve Station Service transformers. The emergency switchgear buses remained energized, continuously throughout the event, from both 115KV offsite power supplies; however, the flags appeared on the degraded voltage relays. This indicated that the voltage level on the emergency switchgear buses had reached a value which started the time delay relays for undervoltage protection. The offsite power breakers did not trip nor did the emergency diesel generators start since the transient undervoltage condition cleared before the time delay setting of the relays was satisfied. Safety related electrical distribution systems are physically separated and electrically isolated from the normal (non-safety) systems downstream of the Reserve Station Service transformers. Therefore, any fault on the non-safety related systems cannot adversely affect the safety related electrical distribution system.

Power supply from plant normal uninterruptible power supplies, 2VBB-UPS1A, 1B, 1C, 1D, and 1G tripped during this event. This indirectly caused the feedwater, condensate booster, and condensate pump minimum flow valves to fully open (as designed). Opening of these minimum flow valves resulted in the operating feedwater pumps tripping on low suction pressure. However, RCIC and HPCS were available to provide water to the reactor.

Illumination to certain areas of the plant was partially lost due to loss of normal UPS power; specifically, Essential and Egress lighting was lost. As previously discussed, normal lighting in certain areas of the reactor building was also momentarily lost due to the transient. However, the majority of the areas operators had to access, during the event, were adequately illuminated from plant Normal, Emergency, and 8 hour battery pack lighting. Only illumination in the stairwells was not available. Potentially, lack of illumination could have imposed a personnel safety concern; but this was mitigated by operators using hand held lights during the event for these areas. Use of portable lights is noted in the NMP2 USAR section 9.5.3.3. Lighting needs during this event were adequate and did not adversely impact operator response. The Normal, Emergency, Essential, Egress, and 8 hour battery pack lighting provisions for the plant are described in USAR Section 9.5.3.

The Reactor Manual Control System (RMCS), as described in USAR Sections 7.7.1, is an instrumentation and control system whose function is not essential for the safety of the plant. The RMCS as described in USAR Section 7.7.1.1.1, was lost during this event because its power source, the normal nonsafety related UPS, was lost. The RMCS provides the operator with means to manipulate control rods so that reactor power level and core power distribution can be controlled. This system is a power generation system and is not classified as safety related. The RMCS does not include any of the circuitry or devices used to automatically or manually scram the reactor. The RMCS control and position indication circuitry is not required for any plant safety function nor is it required to operate during any associated DBA or transient occurrence. The reactor manual control circuitry is required to operate only during normal power generation operations. The inoperability of the RMCS during this event is consistent with the discussion in USAR Sections 7.7.1 and 7.7.1.1.1 and is therefore, acceptable. See Recommendations, item 9.

The main plant annunciators and computer systems were lost with the loss of the normal UPSs. The annunciators and computer systems are important to aid the control room operators during all periods of operation and during both normal and emergency shutdowns. However, these systems are designated as non-safety related. They are not required to perform any safety function to shutdown the plant. See Recommendations, item 6.

ASSESSMENT OF HUMAN FACTORS ISSUES

Summary

The plant operating staff acted in accordance with the EOPs. Their response reflected a professional attitude, good training, and a team approach to the event as it unfolded. The operating staff successfully handled various plant anomalies during the event. This response demonstrated a knowledge of plant procedures, a commitment to following these procedures, and the ability to assess and evaluate situations correctly as they were manifested during the event.

OPERATOR RESPONSE

An assessment regarding the ability of operators to perform required actions during the UPS power loss was undertaken. This was conducted by review of operator written statements, shift debriefing, and operator interviews.

The loss of lighting was determined not to impact operator actions. The only prolonged loss was that of essential lighting which impacted stairway lighting. (Reactor Building lighting went out initially but came back on within 30 seconds.) However, operators carried flashlights, therefore, the operators felt that the loss of stairwell lighting did not impact plant operations.

Communications systems were also lost while the UPS power supply was deenergized; specifically, the GAItronics and radio systems were impacted. Loss of these systems caused reports and directions to and from the Control Room to be delayed. Operators stated that had communications been available restoration of power may have been quicker but also noted that they still were able to carry out required actions.

Instrumentation availability was reviewed to determine if EOP use was impacted. Interviews with operators and panel walkdowns have verified that all parameters were available that were required to be monitored for this event in order to implement the EOPs. This includes EOP entry condition parameters as well as those required to make various decisions throughout the procedures.

A review of applicable technical specification (TS) requirements has been made for the time period this event was in progress. It has revealed that all TS limiting conditions for operation (LCO) requirements were adhered to with <u>exceptions</u> described as follows:

- TS 4.6.4.b.1 This TS surveillance requirement specifies cycling the drywell - suppression chamber vacuum breakers through one complete cycle of full travel within two hours following a safety relief valve (SRV) actuation. However, it was not determined that SRVs had actuated until approximately

four hours following event initiation. At that point the required surveillance was successfully completed in the following two hours. Therefore, delaying this surveillance had little or no safety impact. See Recommendations, item 10.

- TS 3.3.1 action b. This TS action requirement specifies placing at least one RPS trip system in a tripped condition within one hour. Using N2-EOP-6, Attachment 14 operators had defeated all RPS interlocks (except for manual), as directed by the EOPs, for a period of approximately one and one half hours. This was required in order to permit resetting the scram signal to allow the scram discharge volume (SDV) to drain down so operators could perform additional scrams to effect control rod insertion. This action is directed by NMP2 EOPs consistent with the BWR Owners Group (BWROG) emergency procedure guidelines (EPG) Revision 4 and is recognized in the Safety Evaluation (SER) for NMP2 EOPs (SER 90-145 Revision 4, Attachment 4, Event 15.8). Additionally EPG Appendix B specifically states the following "... This is not to imply that operation beyond the Technical Specifications is recommended in any emergency. Rather, such operation is required and is now permitted under certain degraded conditions in order to safely mitigate the consequences of those degraded conditions...."

Defeating RPS interlocks, in accordance with the EOPs, was required in order to insert control rods since the operators were unable to determine multiple control rod positions. The bases for the EOPs and their safety evaluation recognize the potential for this condition; therefore, the action taken by the operators, based upon the direction given by the procedures, was appropriate and conservative.

A review of the NMP2 EOP (Rev. 4) Safety Evaluation (90-145) for analysis of USAR events 15.2.3 (Turbine Trip) and 15.8 (ATWS) has been completed. The only difference between actual operator performance and that described in the safety evaluation was that operators entered the EOPs based upon low RPV water level vs high RPV pressure assumed in the safety evaluation. However, this had no impact on procedure use or plant conditions.

The above differences are acceptable based upon the following assessment:

(1) Control rod position indication was inoperable during the event; however, operators subsequently determined, during the event, that an ATWS had not occurred. Therefore, comparison of operator action during the plant event to the ATWS USAR analysis/safety evaluation is not warranted.

(2) During the event, a turbine trip did occur. Therefore, it is appropriate to compare the event to the USAR analysis/safety evaluation for a turbine trip. The USAR describes the turbine trip transient in section 15.2.3 and on Table 15.2-3. A review of the USAR Table 15.2-3 indicates that a total of 18 SRVs actuated in the relief mode by analysis while only 2 SRVs actuated in the relief mode during the plant event. Discussions with General Electric concerning the plant response and the USAR analysis, as it relates to the number of SRVs actuated, has resulted in the following assessment:

(a) The plant event of 2 SRVs lifting is consistent with the power ascension program test results of 2 SRVs lifting as described in startup test procedure N2-SUT-27;

(b) The USAR analysis is extremely conservative due to the maximization of all uncertainties in a direction which would maximize the number of SRVs challenged to lift;

(c) A turbine trip event during the beginning and mid cycle timeframe is considered a mild event in terms of number of SRVs actuated, where as the USAR analysis is performed at the end of core life, which is the most limiting portion of the core life.

Therefore, this report concludes that the number of SRVs actuated during the event is consistent with the USAR analysis.

(3) The event also involved a loss of feedwater flow. Considering the plant event (a turbine trip), which resulted in 2 SRVs actuating as opposed to 18, concurrent with the loss of feedwater flow, the dominating reactor parameter for EOP entry would be RPV level and not RPV pressure. Therefore, the entry into the EOPs based upon low RPV level is consistent with the USAR analyses/safety evaluation.

In conclusion, based upon the above assessment in items 1, 2 and 3, the differences identified between USAR analysis/NMP2 EOP safety evaluation and operator actions in entering the EOP's does not present a safety concern or require changes to the EOP's.

DESCRIPTION AND ASSESSMENT OF THE ENVIRONMENTAL IMPACT OF THE AUGUST 13 TRANSFORMER OIL SPILL

On Aug. 13, 1991, the Supervisor of Environmental Protection, was notified of the oil spill from transformer 2MTX-XM1B. The New York State Department of Environmental Conservation (DEC) was notified at 12:05 p.m. A courtesy notification was made to the National Response Center at 12:52 p.m. on 8/13/91.

The storm sewers, oil separator and visual observation of the lake shoreline (where the storm sewer enters the lake) revealed no oil had leaked to these areas. A small amount of oil had sprayed outside of the transformer containment pit. The stones and small portion of dirt have been removed and are waiting to be properly disposed of in accordance with the DEC. The oil that remains within the transformer containment pit will be evaluated for removal. Therefore, it can be concluded that no offsite environmental impact occurred as a result of the transformer oil spill.

OVERALL ASSESSMENT CONCLUSION

In response to an electrical transient, Nine Mile Point Unit 2 was safely and effectively shutdown and brought to a cold shutdown condition. Overall, the response of the facility was well within the scope of the safety evaluation of the unit as discussed in the USAR. The operator, operating staff, and emergency response organization acted in accordance with procedures, professionally, and were well trained to handle the situation as it developed. At no time during this event was there any release of radioactive material nor was the health and safety of the public affected.

RECOMMENDATIONS

In prior sections of this report, the plant response to this event was evaluated with regard to the safety significance of the event sequence. The conclusions reached have confirmed that no safety issues exist; however, issues remain regarding improving operability of the plant under transient conditions.

Reliability of the normal plant UPS system is necessary in order to minimize the plant anomalies experienced upon a loss of one or more UPSs. The normal UPSs are intended to operate with either a normal AC supply, station battery supply, or a maintenance AC supply. These different power supplies provide three independent sources of power which would provide the level of reliability necessary for this very important power system. Upon completion of the UPS root cause evaluation and upon implementation of action, the necessary level of reliability should be restored to the uninterruptible power supply system.

Based on the evaluations performed, as part of this safety assessment, recommendations were developed. These recommendations do not affect the ability to safely operate the plant while they are being considered. The evaluation process will consist of a team approach whereby engineering and plant operating staff will participate in an interactive process to evaluate and disposition the recommendations. Recommendations, (7) and (8), discussed below, were not previously evaluated in this report; however, these recommendations are provided based upon the safety assessment team's review of the sequence of events during the plant transient. The recommendations are:

1. <u>In-Plant Oscillograph</u>

   An evaluation of the in-plant oscillograph installation is required in order to improve the availability of data following electrical distribution system transients. Availability of an in-plant oscillograph will improve the ability to evaluate the origin of faults and the plant's response to such faults.

2. <u>Stairwell Lighting</u>

   During this event, the loss of stairwell and egress lighting was evaluated not to be a safety concern, however, the concern for personnel safety still exists. A modification for Unit 2 currently exists which will address the power supply system for the stairwell lighting which will correct this problem. Consideration should be given to the schedule for implementation.

3. <u>Drywell Cooling Fan Circuit</u>

   The current drywell cooling fan operation relies upon an auxiliary relay circuit which is currently powered from the normal UPS power supply. This circuit should be modified to receive its power from the same power supply which powers the control circuit for the drywell unit cooler fans.

4. Communications - GAItronics/Telephones/Portable Radio System

During the course of this event, the GAItronics public address system was inoperable from the control room. In addition, the portable radio leaky wire system and portions of the in-plant dial telephone system were also impacted during this event by the loss of the normal UPS power supply system. An evaluation of the power supply system for these communications systems should be performed which examines the possibility to improve operation and increase reliability. Also an evaluation of using higher powered radios or additional sound powered jacks/headphones should be considered.

5. Annunciator/Computer Systems Power Supply System

The annunciator system and computer systems lost power from the normal UPS power supply system during this event. An evaluation of the power supply should be performed to determine the feasibility of providing added reliability and/or diversity to the power supply system for plant annunciation and computer systems.

6. BOP Instrument Power Supplies

Power supplies were lost to the balance of plant instrumentation cabinets causing a loss of non-safety related instrumentation. An evaluation of the feasibility of improving the power supply system to add reliability through redundancy or diversity in the supplies should be considered and evaluated for implementation for selected parameters.

7. Cooling Tower Bypass Gate Failure Mode

During the course of the event, the cooling tower bypass valves opened and bypassed the tower. This caused a loss of the cooling capability provided by the cooling tower. An evaluation of the cooling water system control circuitry should be performed to determine whether this failure mode is the most appropriate under all transient and normal conditions for the system design.

8. Minimum Flow Valve Failure Mode

Because of the loss of a single UPS power supply to the instrumentation cabinets, the minimum flow control valves for the feedwater pumps, condensate booster pumps, and condensate pumps defaulted to their open position. This caused a major portion of the water from the condensate and feedwater systems to recirculate to the condenser. An evaluation for providing diverse power supplies to the Feedwater Control System should be performed to increase reliability of this system. Also, an evaluation of the feedwater control system logic should be performed.

9. Alternate Methods for Rod Position Indication

During the course of this event, rod position indication in the control room was lost due to the loss of the normal UPS power supplies. An assessment should be undertaken to determine alternate methods for rod position indication under transients of this type and/or an evaluation of the existing power supply system to the rod position indication system should be undertaken.

10. Primary Containment Vacuum Breaker Cycling Subsequent to an SRV Actuation

Control room procedures should be revised to alert the operator to the technical specification requirement to cycling the vacuum breakers within two hours of an SRV actuation. This will reduce the likelihood of a recurrence of violating TS surveillance 4.6.4.b.1.

ATTACHMENTS/REFERENCES:

Attachment - Scram Summary - prepared by E. Tomlinson, NMP2 Reactor Physics

Reference 1- Assessment of Operator Response and Training Effectiveness - prepared by J. Helker, NMP2 Operations

Reference 2 - NMP2 Electrical Distribution System - prepared by A. Julka, NMP2 Design Engineering

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ATTACHMENT

SCRAM SUMMARY 91-01

At 0548 on August 13, 1991, Nine Mile Point Unit Two experienced a turbine trip and automatic reactor scram when the Main Transformer Phase B developed an internal fault (Main Transformer fault details discussed in separate report). The transformer fault created an electrical disturbance throughout the normal electrical distribution system. This electrical disturbance caused UPS 1A-D and G to trip off, de-energizing their respective loads. (Details of UPS trips and electrical system response are discussed in separate reports)

Initially the operators lost most BOP instrumentation and all control room annunciation which created several conflicting indications of reactor status. The SSS ordered the mode switch be placed in shutdown and the crew began to respond to the scram. The crew recognized that feedwater pumps had tripped and initiated Reactor Core Isolation Cooling (RCIC) to control a lowering reactor water level. Reactor systems responded to the turbine trip as expected including a EOC-RPT Recirc pump downshift. Two safety relief valves lifted to limit reactor pressure to 1070 psig. The Redundant Reactivity Control System initiated an Alternate Rod Insertion and Recirc Pump downshift signal on high reactor pressure. Post Accident Monitor recorders shifted to fast speed and continued to provide reactor pressure and water level indication.

When reactor water level reached Level 3 (159.3 inches), operators entered the Emergency Operating Procedures (EOPs) for RPV control. Due to lack of control rod position information, operators also entered C5, Level/Power Control. In accordance with C5, automatic ADS operation was inhibited. Because RCIC was running, operators placed RHR loop A in Suppression Pool cooling. Per EAP-2 the SSS/SED declared a Site Area Emergency due to loss of control room annunciators with a plant transient in progress. Reactor water level was recovered using RCIC. The lowest level reached was approx. 145 inches, well above any ECCS injection setpoints. When water level returned to the normal band, RCIC was realigned to pump CST to CST. As water level continued to rise, operators recognized that reactor pressure was below the discharge pressure of condensate booster pumps and tripped them off. Reactor water level at that time was approximately Level 8 (202.3 inches). The cold water expanded and water level continued to rise. One CRD pump was left running to support control rod insertion. Water level was offscale high on the only operating recorders for approximately 8 minutes. During this interval water level was conservatively estimated to reach a maximum of 243 inches (9 inches below the main steam lines).

At approximately 0622, operators restored power to the UPS buses. With power restored to Reactor Manual Control System, the Full Core Display, Rod Worth Minimizer, and Rod Sequence Control System gave some conflicting information on control rod position.

Using RPV control, section RQ, operators installed RPS jumpers and reset the scram. At that point all rods indicated full in. With RCIC running CST to CST and condensate booster pumps secured, reactor water level decreased. Condensate Booster Pump P2A was restarted to control water level however the feedwater pump suction valves (CNM-MOV84) would not reopen presumed at the time due to high dp. Operators could not manually equalize pressure across the valves due to the SSS restricting access to the turbine building.

Operators used the low pressure/low flow valve (CNM-LV137) to control level. Water level dropped to Level 3 (159.3 inches) again and EOPs were reentered. Water level lowered to a minimum of approx. 124 inches (approx. 15 inches above an ECCS injection setpoint) before returning to the normal band.

At 0950 UPS 1C and 1D were restored to their normal power supplies UPS 1A and 1B had to be left on maintenance supply due to equipment failures. During the shutdown, several equipment failures created additional burden on the control room staff. These equipment problems are described in the Sequence of Events and the Deficiencies list.

In evaluating this transient against the USAR transient analysis the following conclusions were made:

1) Reactor pressure rise as shown on both Post Accident Monitoring recorders is much less severe than the pressure rise shown on Figure 15.2-1 of the USAR (Generator Load Rejection with Bypass) 1070 vs 1150.

2) Reactor water level as shown on both Post Accident Monitor recorders is slightly lower than the USAR, however this discrepancy was due to all feedwater pumps tripping off.

3) Neutron flux was not recorded however, the conditions used in the USAR which influence the flux spike such as pressure rise, scram speed and void fraction are all more severe than actual conditions. In addition N2-ISP-NMS-W@007 "APRM Functional Test" was performed on 8/14/91, and verified proper operation of APRM flux scrams.

4) Based on personnel interviews and review of as found conditions, we believe that all plant systems designed to mitigate the severity of this event, (ie EOC-RPT, Turbine bypass valves, SRVs, ARI) functioned as required.

Based on the above conclusions, the results of this transient were within the bounds of current transient analysis.

Scram Evaluation Team:

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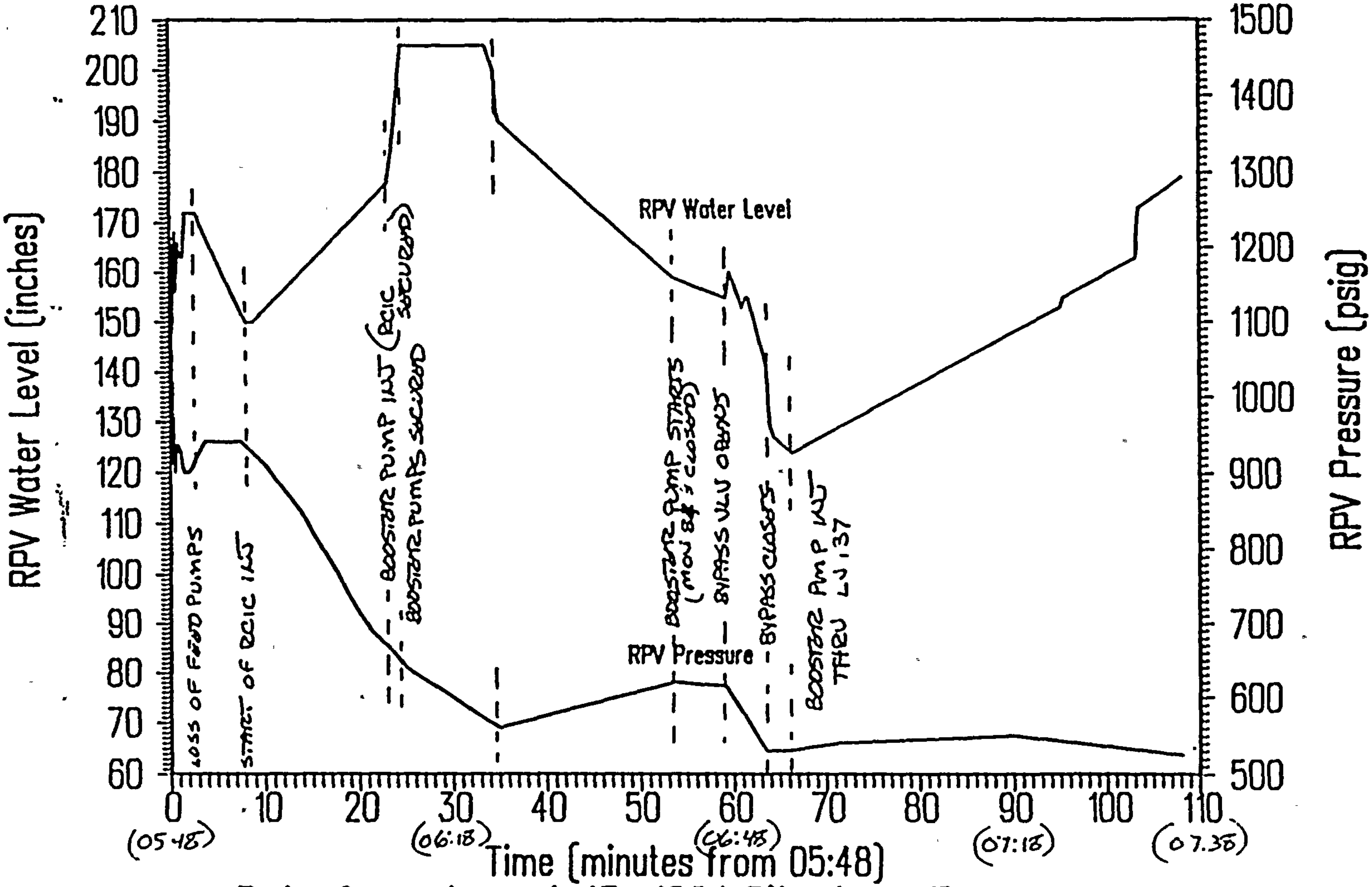
	Dorry Crager
	Brian Wade
	John Baudanza
	Jerry Helker (SRO)
	Various System Engineers

Nine Mile Point Unit 2
Reactor Pressure and Water Level vs Time



Data from August 13, 1991 Site Area Emergency

SEQUENCE OF EVENTS SCRAM 91-01

The attached Sequence of Events is a reconstruction of the events that occurred on August 13, 1991. Due to the loss of Uninterruptible Power Supply (UPS) power, normal means of recording the event were initially unavailable. Control Room meters and recorders, powered from the affected UPSs, were inoperable during the first 34 minutes of the event. The Plant Process Computer was unavailable an additional 49 minutes. This Sequence of Events is based on operator interviews and written statements, operator logs, Post Accident Monitor (PAM) recorded plots, Turbine/Generator flags, and crew debriefs. Significant effort was made to ensure the validity of the event sequence and times of occurrences. However, due to the above-mentioned conditions, this Sequence of Events is essentially a "best approximation" of the actual event sequence.

TIME	INDICATIONS/PROBLEMS/ACTIONS	REASON/JUSTIFICATION
0548	Loss of Transformer 1B due to Fault	Under Investigation
	Customer Trip of Main Turbine, TSV/TCV shut. Reactor Scrams. Turbine bypass valves open.	See attached list of relay flags. TSV/TCV fast closure. Automatic to control pressure.
	Fast Transfer from Normal Station[1] Power to Reserve Power.	See attached list of relay flags.
	Failure of UPS 1A-D,G, failed to maintain a power supply to non-safety vital buses. - Loss of Radio Leaky Wire Antenna System. - Loss of Control Room Annunciators. - CWS-MOG 52s Cooling Tower Bypass Valves went open. - Loss of Computers (Process, SPDS/ERF, GETARS, GEMS, DRMS, 3D-Monicore). - Loss of Gaitronics. - Loss of BOP Instrumentation. - Loss of Essential Lighting. - Off Gas Isolation. - P603 panel Recorders Fail as is. - FWS-LV10s Lockup in open position. - Loss of Drywell Cooling. - Loss of Rod position indication. - Feedwater and Condensate Booster Pump minimum flow valves fail open.	UPS Failure Under Investigation. Resulting from Loss of UPS.

1 - As shown by Scriba Oscilloscope

TIME	INDICATIONS/PROBLEMS/ACTIONS	REASON/JUSTIFICATION
	ARI and PAM to fast speed at 1050 PSIG.	Normal response to hi pressure due to Turbine trip from high power.
	2 SRVs lift at 1070 PSIG.	
	After pressurization event PAM Recorders on P601 are used for Reactor level and Pressure Indication. Level ~ 175" Pressure ~ 920#	Used as reliable indication with redundant sources.
	Observed Scram Pilot lights are out.	Due to Auto Reactor Scram.
	APRM Meters and LPRM Lights on back panels are Downscale, Scram Logic Lights are out, Scram Discharge volume is full.	Operators used various methods to determine reactor power.
	Operators dispatched to verify scram air header pressure and monitor reactor pressure and water level on local indicators.	Backup indications.
	Recirc pumps Downshifted due to EOC RPT and RRCS Hi Reactor Pressure.	As designed.
	Observed Feedwater pumps and Condensate Booster pump 2A tripped. Condensate Booster pump 2C Auto Starts.	Minimum flow valves failed open - see attached memo.
	Division II H2/O2 Sample Pump Trips Off.	Spurious trip unrelated to UPS problems
0549	Mode switch is placed in shutdown.	Ordered by SSS as conservative action.
0555	Manually initiated RCIC due to lowering Reactor vessel level and no feed pumps running. Experienced flow, speed and pressure oscillations while in Auto Control, therefore transferred to Manual control.	Ordered by SSS to control water level.
	Reactor Recirc Runback at L4 (178.3").	Auto response.

TIME	INDICATIONS/PROBLEMS/ACTIONS	REASON/JUSTIFICATION
	Groups 4 and 5 Isolations at L3 (159.3")	
0556	Entered RPV control EOP. Entered C5. ADS inhibit switch to on.	Reactor Vessel Water level <159.3" and lowering. No rod position indication. Required by C5.
	Initiated suppression pool cooling using RHS*P1A.	Ordered by SSS due to RCIC operation.
0600	Declared Site Area Emergency.	EAP-2, Loss of all control room annunciators with plant transient in progress.
	Operators dispatched to verify UPS operation.	Ordered by SSS due to diagnosis of control room indications.
0607	Commenced logging cooldown.	EOP-RPV, verify cooldown.
0608	Notified State and local authorities.	EPP-20
0612	Initiated NRC Contact	EPP-20
0612	Controlling Reactor Vessel Water level with RCIC in manual. Reactor level rising. Reactor Pressure lowering.	As directed by C5.
0614	Secured RCIC injection, started pumping tank-to-tank.	Maintaining level control.
0615	L8 (202.3) is reached, Condensate Booster pumps are secured.	Maintaining level control.
	Operator reports that series UPS 1A-D,G have tripped.	
0620	Secured condensate pumps except for P1A. Reactor Vessel Water level is lowering.	Standard operating practice.
0622	Restore UPS 1A-D,G by manually transferring to maintenance bus. Annunciator Power and other indications are restored.	As directed by SSS.

TIME	INDICATIONS/PROBLEMS/ACTIONS	REASON/JUSTIFICATION
	Group 9 Isolation	Restoration of Power to UPSs
	FWS-LV10s closed.	
0630	All rods in except 6 which have no indication on Full Core Display (Rod 14-31 has no indication on RWM, and 15 without full-in indication on RSCS).	Loss of power. See attached memo.
	CNM-MOV84s closed.	OP-3 prerequisite for starting a condensate booster pump.
	Restored Drywell Cooling Highest Temperature -165°F Lowest Temperature -120°F	Per Operating procedures.
0640	Started Condensate Booster Pump P2A to maintain Reactor Water level 165" - 180".	Level steadily lowering.
	Attempted to open MOV 84A & B after booster pump running. Received dual indication.	Under Investigation.
	Opened FWS-LV55A in an attempt to establish feed flow to vessel. No flow due to CNM-84S closed.	
	Re-entered RPV EOP on level. Using LV-137 to control Reactor Vessel Water level.	
0645	Reset Rod Drive Control System.	RDCS not scanning due to loss of power.
0650	Installed RPS jumpers per EOP-6 Att. 14.	To enable resetting scram.
0653	Reset scram.	EOP-RPV, Section RQ
0700	All rods indicated full in. Controlling Reactor Press on bypass valves.	
0711	Process computer restored.	

TIME	INDICATIONS/PROBLEMS/ACTIONS	REASON/JUSTIFICATION
	Division II H_2 O_2 Sample Pump restarted.	Found tripped by operator.
0729	Started mechanical air removal pumps. No Auxiliary Steam to Clean Steam Reboilers. Started Aux Boiler. Had to pin open AOV-145.	Maintain condenser vacuum.
0732	Main Turbine would not go on turning gear.	See attached memo.
0738	Started Condensate Pump P1B.	To clear high stator temp on P1A due to high flow.
0740	RCIC Shutdown to standby.	No longer needed.
0750	SPDS restored.	
0758	Hydraulic Power Units Reset.	Normal response.
0805	Stack Gems reported Inop. Computer department started rebooting system.	Computer did not restore itself properly after power was restored.
0806	RCS Flow Control Valves full open.	N2-OP-29
0810	Completed restoring RHR Loops B and C to operable.	B and C loops were marked up prior to the event for corrective and preventative maintenance on various valves and instruments.
0821	ADS inhibit switch to Normal, RPS jumpers removed.	EOP Recovery.
0847	Stack Gems computer restored.	
0937	RCIC INOP AOV156 did not indicate shut, MOV126 de-energized shut per Technical Specifications.	Technical Specifications 3/4.6.3
0950	UPS 1C & 1D restored to Normal Power, could not restore 1A & 1B to Normal Power, left selected to maintenance.	Per SED
1006	Drywell vacuum breaker operability test was performed as required by Tech Specs.	Had just determined that two SRVs had lifted at the beginning of the event.

TIME	INDICATIONS/PROBLEMS/ACTIONS	REASON/JUSTIFICATION
1020	UPS 1G restored to normal power.	Per SED.
1031	Group 9 Isolation Reset.	Normal Recovery.
1055	Started Reactor Water Cleanup Pump P1B for full reject.	For chemistry and water level control.
1056	Reactor Water Cleanup Pump P1B trips when Reactor Water Cleanup Isolates due to Delta Flow.	Root cause in progress. No equipment damage. See Engineering memo.
1158	Secured RHS Pump P1A.	Needed to stroke MOV40A for PMT. Two loops of shutdown cooling are required by Tech Specs.
1217	Reset RHR shutdowwn cooling, RWCU, and Group 4 Isolations.	
1415	Shut Condensate AOV109 (condensate bypass).	For chemistry concerns.
1458	Shutdown RCS Pump P1B for shutdown cooling.	OP-31
1508	Started RHS Pump P1B in shutdown cooling mode.	OP-101C/31
	Experienced difficulty in controlling Reactor Vessel Water Level.	Initially unable to properly throttle RHS*MOV142, RHR Discharge to Radwaste, from Control Room. Opened locally.
1519	Shutdown Condensate Booster Pump P2A.	OP-101C
1520	Shutdown Condensate Pump P1A.	OP-101C
1807	Shut 2FWS-MOV21A & 21B.	OP-101C
1846	Reactor is in Cold Shutdown.	
1943	Terminated Site Area Emergency.	Per SED.

Deficiencies Noted during the Event and Open Items

1) Reactor Water Chemistry Excursion
   - Yang Soong of Nuclear Technology has analyzed the chemistry excursion. His recommendations to Chemistry were that 1) this startup ocur at a slower rate that normal in order to minimize the effect of any remaining chemical species in the vessel, and 2) Maximum RWCU flow be maintained throughout startup.

2) Water hammer in WCS
   - Engineering evaluation - memo SM2-M91-0213
   - Inspection of WCS piping was performed on August 13, 1991, at approximately 1950 hours by Engineering and Radiation Protection. This inspection revealed no abnormal conditions and Engineering has no reservations regarding return of WCS back to service.

3) 2ASS-AOV145 had to be pinned open
   - WR 178843, WR 164466, WR 193588
   - ASS-AOV145, Aux Boiler Steam Inlet Control to Reboilers, has an air leak at its control block. The leak causes a loss of air to the valve and subsequent valve closure. Once opened, the valve had to be pinned open.

4) Water hammer in RHR
   - Engineering Evaluation - memo NMP77864
   - Inspection of the RHR Piping System was performed on August 13, 1991, at approximately 1350 hours by Engineering and Radiation Protection. This inspection revealed no abnormal conditions and Engineering has no reservations regarding return of RHR back to service. This inspection was performed while the loop was warmed up for the second time. No procedural problems were identified.

5) Friskall on Reactor Building Exit
   - WR 192659
   - During the Site Area Emergency, two of the three Friskalls at the Reactor Building were initially not available. One was reset by 0700 and the other required a Work Request. The WR was completed August 17, 1991.

6) 2CNM-MOV84s couldn't be open
   - WR 192891, WR 192892, WR 194591, Engineering Evaluation
   - Attempts to open the feedwater suction valves were unsuccessful due to differential pressure (approximately 500 psig) across the valves. WRs were submitted to check torque settings. Investigation is continuing.

7) Chemistry Sampling and Analysis

- Chemistry Evaluation
- The normal sample tap was not available due to the WCS isolation, requiring operator action to valve-in the alternate sample tap. The Loop A tap is not normally valved into service as a result of an engineering assessment of flex hose failure. Chemistry is to submit a DER to request Loop A sample tap continuous service.
- Loss of power to chiller caused the temperature switch to trip. The local thermal reset was required to be depressed and held for five seconds. The Chemistry Technician did not wait the required time and the temperature switch didn't reset.
  This delayed the sample approximately 15 minutes. An Operator Aid has been developed to identify the five second time requirement.
- The gamma spectrometer was in use for the stack sample analysis. The spare gamma spectrometer in under repair. The unit is to be repaired consistent with department priorities.
- Communication was sometimes confusing between lab, OSC, and TSC. Emergency Planning is to revise OSC to facilitate control of Chemistry Sample teams.
- Ion Chromatographic analysis dilution and contamination problems were encountered. All chem techs qualified in ion chromatography will be requalified by September 5, 1991.

8) Trouble with getting turbine on turning gear

- System Engineer Evaluation, DER 2-91-Q0868
- Following turbine coastdown, the turning gear motor tripped on overcurrent and allowed the rotor to come to a complete stop. Subsequent attempts to put the turbine on the turning gear resulted in motor overloads due to the thermally induced bowing of the rotor. The rotor cooled for approximately eight hours and was then placed on the turning gear. A subsequent walkdown revealed no unusual conditions. It is known the turning gear occasionally trips on overcurrent during coastdown and there are no special recommendations for turbine startup or shutdown as a result of this event. A DER was initiated to address this recurring problem.

9) ICS Outboard check valve 2ICS-AOV156 indication

- WR 193343, WR 194584
- With the ICS system secured, testable check valve AOV156 indicated full open on PNL601. During performance of WR 193343 for correction of the indication problem, it was noted the valve packing was leaking. Performance of WR 194584 corrected the packing leak.

10) Two sumps on Rx 175' slightly overflowed
- WR 193371
- All Equipment Drain Sumps on Rx 175' overflowed to Floor Sumps with only DER Tank 2A (at ramp) exceeding boundary area. Walkdown on August 26, 1991, showed leakage to be from DFR TK2A discharge hose within the sump.

11) MSIV AOV6D Dual Indication
- WR 193349
- 2MSS*AOV6D indicated dual position when taken to close. The WR is complete.

12) No Aux Main Steam to Clean Steam Reboilers due to PV113
- WR 193207
- 2ASS-PV113, Clean Steam Reboilers Control Valve, does not control steam pressure when 2ASS-STV112 is open. Scheduled for work August 27 and 30, 1991.

13) LOCA Bypass Switches do not work without UPS (Black) Power
- Plant Change Request - PC2-0258-91
- Request for LOCA override switches and logic to be able to function without (Black) UPS power.

14) 2CNM-AOV101 Open
- Procedure Change Evaluation
- PCE submitted to add reclosure of AOV101, bypass around low pressure feedwater heaters, and AOV109, bypass around condensate demineralizers, after scram to OP-101C. AOV109 was closed to address potential chemistry concerns. AOV101 was closed after cold shutdown.

15) ODI 5.16 Skills of the Trade
- Procedure Change Evaluation
- PCE submitted to add manual breaker operation for 600V and less. This change has been completed.

16) Reactor Vessel Upset range not available on Process Computer and not powered from Safety Related Bus
- Plant Change Request PC2-0257-91
- Request that Reactor Vessel Upset range instrumentation be powered from a Safety Related bus and recorded on the process computer in order that level may be recorded during transients that involve power failure.

17) RHS*MOV142, RHR Discharge to Radwaste, would not initially open from PNL601
- WR 193350
- The throttle discharge to radwaste would not open from the control room and had to be manually opened at the valve. The WR was completed on August 13, 1991.

18) Cooling Tower Bypass Gates fail open on loss of power to temperature instruments.

- Plant Change Request - PC2-0288-91
- Loss of UPS power caused the temperature instruments in the basin to fail downscale, sending a signal for the bypass gates to open. This could have caused an overflow of the basin (in this event the basin did not overflow) and a loss of the circulation water heat sink. The plant change request was submitted to change the logic so that the bypass gates fail closed.

19) Transformer 1B Fault

- Root Cause being investigated
- Transformer being removed. Spare Transformer to be used.

20) UPS1A-D and G failed to transfer

- System Engineer Evaluation continuing

21) Feedwater and Condensate Booster Pumps trip off

- System Engineering Evaluation
- Loss of UPS1A and 1B resulted in loss of flow signals to the minimum flow valves for both the feedwater and condensate booster pumps. This caused the system flow to exceed the supply capacity of the condensate system, causing system pressure to decrease.

  The operating "B" and "C" feed pumps and "A" condensate booster pumps tripped on low suction.

22) Control Rod position indications not consistent

- System Engineering Evaluation
- During two verifications the following conditions were noted:

  a) RSCS indicated that 15 rods were not full in.
  b) The Full Core Display (DMM) indicated that 6 rods were not full in.
  c) The RWM indicated that all rods were full in.

- The operation and indications produced by the Reactor Manual Control System are different for each of the three indicating sub-systems.

  a) RSCS ---"Full-In" and no "Data Fault".
  b) DMM ---"Full-In"
  c) RWM ---(Tens, Units 0,0) or "Full-In" or Latch Function.

  The solutions could be to use RWM and DMM for full-in rod position verification or change the data fault data-bit... on the Probe Data Processor III Card. Use of the RWM in conjunction with the Full Core Display and RSCS vise RSCS alone is highly recommended.

(This method of verification of rod position post scram is already incorporated in current operating procedures.)

23) Stack GEMS Computer did not properly restart when power was restored
- DER 2-91-Q-730, Chemistry Evaluation
- The Stack GEMS was operable during and after the site area emergency although the Control Room Chart Recorder lost communication with GEMS for a brief period. Particulate and iodine sample acquistion was continous during and after the event. Computer Control of the system was interrupted for two (2) brief periods.

24) The following ESF Actuations will be covered by LER 91-17

• Scram	DER 2-91-Q-708
• Group 9 Isolation	DER 2-91-Q-773
• RWCU Isolation	DER 2-91-Q-710
• Group 4 Isolation	DER 2-91-Q-798

25) Missed required Tech Spec Surveillance
- DER 2-91-Q-709, System Engineer Evaluation
- Tech Spec 3/4.6.4, Suppression Chamber/Drywell Vacuum Breaker, require that...operability shall be demonstrated within 2 hours after any discharge of steam to the suppression chamber from the safety/relief valves, by cycling each vacuum breaker through at least one complete cycle of full travel". The actuation of two safety/relief valves wasn't discovered until approximately four hours after they actually lifted so this Tech. spec. was not met within the required time limit.

26) Missed required Tech Spec Action (RPS Inop due to EOP Jumpers)
- DER 2-91-Q-74B & Section from J. Helker's report "Assessment of Operator Response"
- Defeating of RPS interlocks is authorized by the EOPs for this particular scenario in order to provide the ability to reset the scram and perform multiple scrams. This Tech Spec action request specifies placing at leat one RPS trip system in a tripped condition within one hour. Using N2-EOP-6 Attachment 14 operators had defeated all RPS interlocks (except for manual) as directed by the EOPs for a period of approximately one and one half hours. The basis for the procedures and safety evaluations recognize the potential for this condition, thus, the action taken by the operators and direction by two procedures was appropriate.

27) DIV II H_2/O_2 Sample Pump Trip (2CMS*P2B)

- WR 190966 & 196053
  WR 190966 (910824) is closed. Work Item Description: During Plant Transient on 910813 Div. II Pump (2CMS-P2B) tripped for no obvious reason. Div. I CMS and all other Div. II CMS SOVs were found in their normal positions. Determine cause of pump trip and correct if required. Cause of failures: None found, possibly spurious.
- Following completion of the WR I&C traced the wires through the electricl downings and determined that pump *P2B was wired to the correct power panel.
- Subsequently NMP2 Operations tripped pump *P2B by opening its power panel breaker.
- WR 196053 (910829) is still open. Work Item Description: check the breaker for pump *P2B.

28) RCIC Flow Oscillations

- WR 184909 and 189944
- WR 184909 (910814) is still open. Work Item Description: After several minutes of operation during the RCIC Quarterly Surveillance the RCIC Flow Controller in auto began to hunt at approximately plus or minus 50 GPM about its set point of 600 GPM.
  Need Control Loop Setting Verification per attached and troubleshoot as necessary.
- WR 18994 (910627) is still open. Work Item Description: RCIC Turbine Speed Exhibits hunting during surveillance test; perform applicable procedure steps (N2-IMP-ICS-@001) to tune up the RCIC Control System.

29) Drywell Temp indicator discrepancy CMS*TRX130

- WR189947
- WR 189947 (910819) is still open. Work Item Description: Pen showing elevation 307 temperature on the Drywell temperature recorder did not move during temperature transient in the Drywell.

30) Fire panels affected by transient

- Letter from A. Andersen dated August 15, 1991.
- 18 of 20 fire panels at Unit 2 maintained normal power supply. Two fire panels transferred to internal battery backup. There was no interruptions or decreases of fire protection/detection/suppression at the local fire panels.

31) Group 9 Isolation

- System Engineering Evaluation.
- Upon loss of UPS1A, automatic isolation of Group 9 valves was lost. Also, loss of UPS1B resulted in loss of 2GTS-RE105, causing the radiation monitor trip contacts to close. This closed contact feeds a 15 second time delay relay in the isolation logic.

When power was restored to UPS1A, the Group 9 isolation logic was restored, causing the relay fed from the radiation monitor to time out, which resulted in the Group 9 isolation.

32) WCS isolation
- Operations Evaluation of Operating Procedure.
- Root Cause under investigation by Operations Department.

33) Verification that EOP Actions Restored to Normal
- Attachment 14 (Alternate Control Rod Insertions) to N2-EOP-6 which installed the RPS Jumpers has a hand written double verification of their removal.
- The ADS inhibit switch is a Control Room front panel switch on panel P601 which has been verified to be back in its normal position.
- A Procedure Change Evaluation (PCE) will be written suggesting that all EOP-6 attachments have double verification steps after all restoration steps.

- A second PCE will be written suggesting that the startup check list for N2-OP-101A have two additional line items.

  a) Was Nine Mile Point Two in the EOPs when it was shut down? ______________
  Yes/No

  b) If a) above was yes _verify that_ all EOP-6 related action items have been restored.

LIST OF PROTECTIVE RELAY ACTUATED ON AUGUST 13, 1991

Unit Protection Alt 1

Protective Relay	Lockout Relay	Action	Ref. Dwg.
87-2SPMX01 Main Transformer Differential Protection Relay	86-1-2SPUX01 86-2-2SPUX02	•Initiate Turbine Trip •Initiate Fast Transfer to Reserve Station Transformer	ESK-8SPU01 ESK-8SPU02 ESK-5NPS13 ESK-5NPS14

Unit Protection Alt 2

Protective Relay	Lockout Relay	Action	Ref. Dwg.
87-2SPUX02 Unit Differential Protection Relay	86-1-2SPUY01 86-2-2SPUY01	•Initiate Turbine Trip •Initiate Fast Transfer to Reserve Station Transformer	ESK-8SPU01 ESK-8SPU03 ESK-5NPS13 ESK-5NPS14
63-2SPMY01 Fault Pressure Transformer	86-1-2SPUY01 86-2-2SPUY01	•Initiate Turbine Trip •Initiate Fast Transfer to Reserve Station Transformer	ESK-8SPU03 Sh. 2 ESK-8SPU03 Sh. 1 ESK-5NPS13 ESK-5NPS14

Unit Protection Backup

Protective Relay	Lockout Relay	Action	Ref. Dwg.
50/51N 2SPMZ01 Protection Relay	86-1-2SPUZ01 86-2-2SPUZ01	•Initiate Turbine Trip •Initiate Slow Transfer After 30 Sec. Block Fast Transfer After 6 Cycles	ESK-8SPU04 ESK-5NPS13 ESK-5NPS14

Generator Protection

Protective Relay	Lockout Relay	Action	Ref. Dwg.
Gen. Phase OC During Startup 50-2SPGZ02	86-1-2SPGZ01	•Initiate Turbine Trip •Initiate Slow Transfer After 30 Sec. Block Fast Transfer	ESK-8SPG01 ESK-8SPG04 ESK-5NPS13 ESK-5NPS14

SCRIBA RELAYS

BUILDING #1

Panel 4-25	Loss Ground Line 20
Panel 3-1F	STA Serv. Loss of Source 1 & or #2
Panel 3-7R	Line Protection "A" Package 345 KV. Scriba - Volney #20 46TTA 20
Panel 23R	Line 23 - 67NB/L23 Inst "B" Package Nine Mile 23/DTT Xmit & Rev
	30TRB - 1/L23 Trip R230 TC #2 Trip R925 TC #2
Panel 1-5R	345 NM2 - Scribà 23 Dir Trans Trip Receive "A" 30 TRA-1 L23

2ENS*SWG103

XFMR. FDR. 2EJS-X3A 103-1

Undervoltage Relay Flags in ON;

1) 27BA 2ENS B24
2) 27BB 2ENS B24
3) 27BC 2ENS B24

2ENS*SWG101

XFMR. FDR. 2EJS-X1A 101-14

Undervoltage Relay Flags in ON;

1) 27BA 2ENS A24
2) 27BB 2ENS A24
3) 27BC 2ENS A24

2ENS*SWG102

HPCS METERING CUBICLE 102-7

Undervoltage Relay Flags in ON;

1) 27BA
2) 27BB
3) 27BC

2NPS-SWG002

"B" AUX. BOILER

1) ABM-B1B SWG-002-3
50/51-2-2ABM B51 (INST.) flag in

2CEC-PNL847
(EHC CABINET BAY E)

30 VDC PMG SUPPLY	-HIGH LIMIT -LOW LIMIT
30 VDC HOUSE POWER SUPPLY	-HIGH LIMIT -LOW LIMIT
-22VDC PMG SUPPLY	-HIGH LIMIT -LOW LIMIT
-22VDC HOUSE POWER SUPPLY	-HIGH LIMIT -LOW LIMIT (low limit not lit, WR154662)
24VDC PMG SUPPLY	-HIGH LIMIT -LOW LIMIT
24VDC HOUSE POWER SUPPLY	-HIGH LIMIT -LOW LIMIT
OSC 1 3K HZ	-HIGH LIMIT -LOW LIMIT (WR168493)
OSC 2 3K HZ	-HIGH LIMIT -LOW LIMIT
OSC 3 3K HZ	-HIGH LIMIT -LOW LIMIT
OSC 4 3K HZ	-HIGH LIMIT -LOW LIMIT

THESE ARE LIGHTS THAT ARE LIT ON THIS PANEL THAT ARE NOT IN DURING NORMAL OPERATION.

First Hit Bus! Cust Trip

Copy to:

T. Tomlinson

C. Shawcross

1991 ESL LISTINGS PRIOR TO TRANSIENT

		INFO ONLY?
91-459	RHS B & C work WRs & EPMs	No
91-458B	SCRM "A" failed Calibration Surv	In Mode 1
91-458A	RMS-CAB180 Vent GEMS Surv	No
91-457	GTS*FN1B (GTS Train B) Unit Cooler Work (Div. II)	No
91-456	SWP*CAB146A RHS SW Effluent Loop A Rad Mon	No
91-455	SWP*CAB23A RHR SW "A" Rad Mon	No
91-452	HVC*CAB18A & C Cont Room Air Intake Rad Mon's	No
91-451	SWP*CAB146B SW Effluent Loop B Rad Mon	No
91-431	EGA-HOSE13B Connection to C2B Leaks	Yes
91-427	RMS*RE1D Rx Bldg. ARM Inop	Yes
91-420	WCS-V30A Valve Backseated to stop leak	Yes
91-407	LPM-NBE2A & B, NBV101 Loose Parts Monitor Recirc Loop Set Points too low & ground prob	No
91-374	RMS*RE111 Rx Bldg. ARM Inop	w/112 oper in Mode 1
91-361	CMS*SOV25D SOV won't open	Yes
91-359	HVC*UC107 Repairs to SWP Valve	Yes
91-345	Rx Bldg. Unit Coolers - Set Points raised	Yes
91-278	RHS*MOV40A S/D Cooling Loop "A" Inop until PMT performed	No
91-262	CPS*AOV104, 106 Hold Outs on AOVs for LLRT Failure	No
91-257	Appendix "R" Valves Surv.	Yes
91-255	Control Rod 22-47 Indication @ position 48 Inop	No

1991 ESL LISTINGS PRIOR TO TRANSIENT (cont'd)

91-214	CPS-FN1 Purge Fan Running w/ Drywell open	Yes
91-169	SLS-P1A/B Resolution to NRC in #91-12	No
91-160	OFG-FT13A & B Flow Xmttr Calib	No
91-083	HVR*UC413A & B Dampers shut as per Pr 90-09183	Yes
91-072	ICS*PCV115 Info. Only (PCV115 Failed Open)	Yes
91-068	Appendix R Valves Hold Outs	Yes
91-024	RHS*SOV36B Isolated	Yes
91-016	CMS*SOV26A & C, CMS*SOV23B Deactivated for Failed Surv.	Yes

RESULTS OF UPS FAILURE

1) Loss of Control Room Annunciators

2) Loss of Control Room Computers

3) Loss of Gaitronics

4) Loss of BOP Instrumentation

5) Loss of Essential Lighting

6) Loss of Drywell Cooling

7) Offgas System Isolation

8) Loss of Rod Position Indication

9) Group 9 Isolation

10) P603 Recorders fail as is

11) FWS-LV10s Lockup in open position

12) CWS-MOG52s (Cooling Tower Bypass Valves) went open

13) Loss of Radio Leaky Wire Antenna System

14) Feedwater and Condensate Booster Pump minimum flow valves fail open

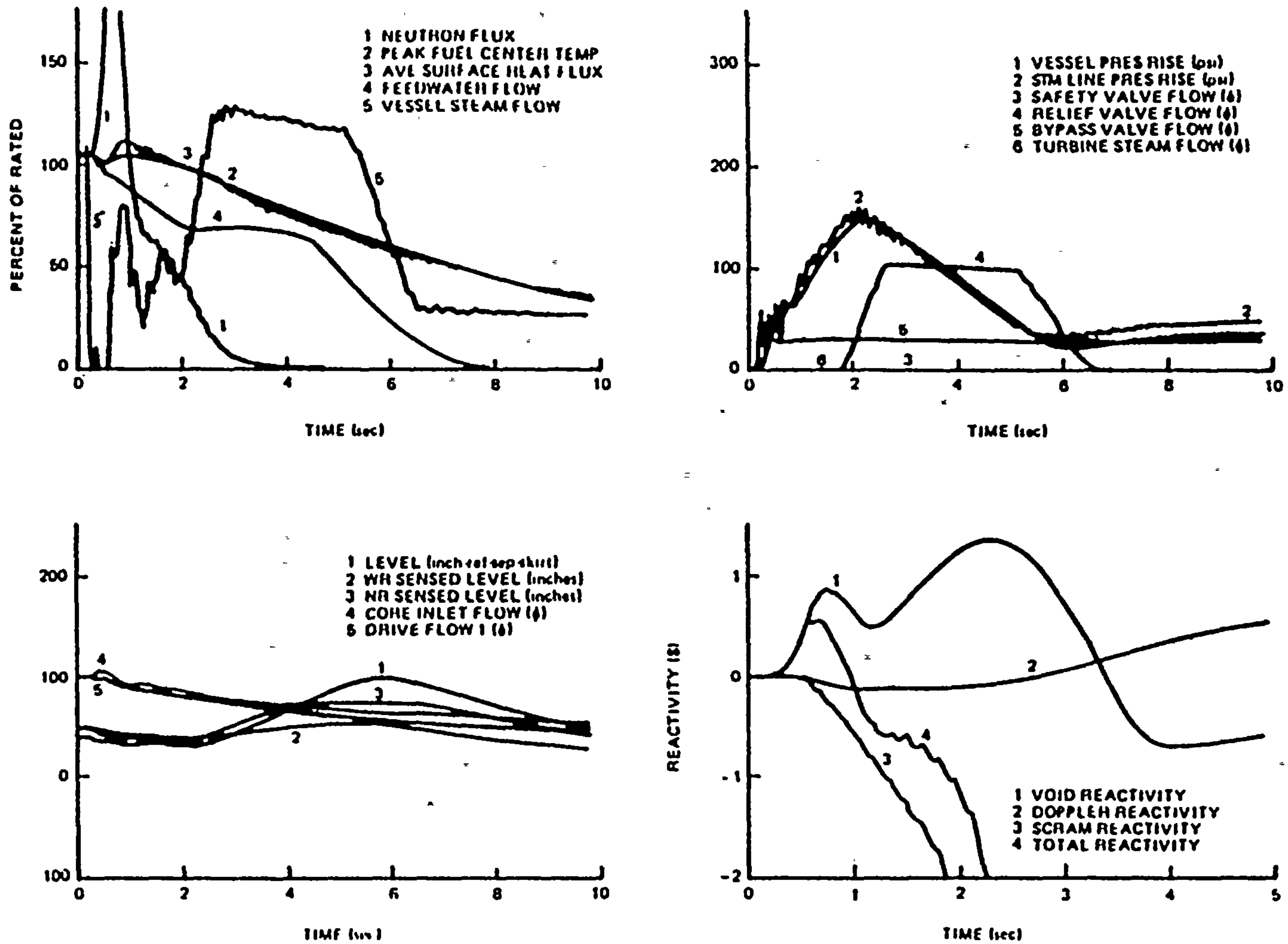


FIGURE 15.2-1

GENERATOR LOAD REJECTION WITH BYPASS

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
FINAL SAFETY ANALYSIS REPORT