ENCLOSURE 1

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE

REPORT NO. 50-220/86-99 and 50-410/87-99
(AMENDED)

NIAGARA MOHAWK POWER CORPORATION

NINE MILE POINT UNITS 1 AND 2

ASSESSMENT PERIOD: UNIT 1 - November 1, 1986 to February 29, 1988
UNIT 2 - February 1, 1987 to February 29, 1988

BOARD MEETING DATE: March 28, 1988

8807180087 880701
PDR ADOCK 05000220
Q PDC

TABLE OF CONTENTS

I. INTRODUCTION

A. Purpose and Overview

The Systematic Assessment of Licensee Performance (SALP) is an integrated NRC staff effort to collect the available observations and data on a periodic basis and to evaluate licensee performance based upon this information. SALP is supplemental to normal regulatory processes used to ensure compliance with NRC rules and regulations. SALP is intended to be sufficiently diagnostic to provide meaningful guidance to the licensee's management to promote quality and safety of plant construction and operation.

A NRC SALP Board, composed of the staff members listed below, met on March 28, 1988, to review the collection of performance observations and data to assess the licensee performance in accordance with the guidance in NRC Manual Chapter 0516, "Systematic Assessment of Licensee Performance." A summary of the guidance and evaluation criteria is provided in Section II of this report.

B. SALP Board

Board Chairman

William F. Kane, Director, Division of Reactor Projects (DRP)
Samuel J. Collins, Deputy Director, DRP

Members

R. Benedict, Project Manager NMP1, NRR
R. Capra, Director, Project Directorate No. I-1, NRR
W. Cook, Senior Resident Inspector, NMP 1 & 2
J. Durr, Chief, Engineering Branch, DRS
M. Haughey, Project Manager NMP2, NRR
J. Johnson, Chief, Projects Section 2C, DRP
R. Keimig, Chief, Safeguards Section, DRSS
D. Lange, Chief, BWR Section, DRS
J. Richardson, Acting Deputy Director, DRS
E. Wenzinger, Chief, Projects Branch No. 2, DRP

Attendees

K. Hooks, Senior Operations Engineer, NRR
R. Laura, Reactor Engineer, DRP
W. Lazarus, Chief Emergency Preparedness Section, DRSS
C. Marschall, Senior Resident Inspector, Ginna
R. Nimitz, Senior Radiation Specialist, DRSS
W. Schmidt, Resident Inspector, NMP 1 & 2
M. Shanbaky, Chief, Facilities Radiation Protection Section, DRSS
R. Temps, Operations Engineer, DRS

II. CRITERIA

Licensee performance is assessed in selected functional areas, depending on whether the facility is in a construction, preoperational, or operating phase. Functional areas normally represent areas significant to nuclear safety and the environment, and are normal programmatic areas. Special areas may be added to highlight significant observations.

One or more of the following evaluation criteria were used to assess each functional area.

1. Management involvement and control in assuring quality.

2. Approach to resolution of technical issues from a safety standpoint.

3. Responsiveness to NRC initiatives.

4. Enforcement history.

5. Operational and Construction events (including response to, analysis of, and corrective actions for).

6. Staffing (including management).

7. Training effectiveness and qualification.

Based upon the SALP Board assessment each functional area evaluated is classified into one of the three performance categories. The definitions of these performance categories are:

Category 1 Reduced NRC attention may be appropriate. Licensee management attention and involvement are aggressive and oriented toward nuclear safety; licensee resources are ample and effectively used so that a high level of performance with respect to operational safety and construction quality is being achieved.

Category 2 NRC attention should be maintained at normal levels. Licensee management attention and involvement are evident and are concerned with nuclear safety; licensee resources are adequate and reasonably effective so that satisfactory performance with respect to operational safety and construction quality is being achieved.

Category 3 Both NRC and licensee attention should be increased. Licensee management attention or involvement is acceptable and considers nuclear safety, but weaknesses are evident; licensee resources appear to be strained or not effectively used so that minimally satisfactory performance with respect to operational safety and construction quality is being achieved.

The SALP Board has also assessed each functional area to compare the licensee's performance near tne end of the assessment period to that during the entire period in order to determine the recent trend for functional areas as appropriate. The trend categories used by the SALP Board are as follows:

Improving: Licensee performance was determined to be improving near the close of the assessment period.

Declining: Licensee performance was determined to be declining near the close of the assessment period.

A trend is assigned only when, in opinion of the SALP Board, the trend is significant enough to be considered indicative of a likely change in the performance category in the near future. For example, a classification of "Category 2, Improving" indicates the clear potential for "Category 1" performance in the next SALP period.

III. Summary of Results

A. Overall Facility Evaluation

Licensee performance during this assessment period has shown limited success with initiatives to improve previously identified weaknesses. Although the staff at Unit 1 demonstrated their technical competence and operating expertise by establishing a record power run, in certain instances there continues to be exhibited a complacent attitude toward the quality of overall station operations. In this area the Unit 2 Operations staff has shown steady improvement, although the rate of personnel errors due to inattention to detail remained high.

Our assessment concluded that the Radiation Protection Program was adequately defined and it was noted that numerous procedural and training enhancements were initiated. However, observations of program implementation indicated that there was inadequate oversight and a general lack of adherence to good radiological controls practices; weaknesses also evident during the previous assessment period.

In the area of Maintenance there has been general improvement as evidenced by the increased oversight of work activities by first line supervision and the development of the Unit 1 Work Control Center. Improvements have also been observed in the area of root cause determination and problem resolution, but further corporate and site management attention is needed to ensure the quality of these evaluations and proper follow through with effective corrective actions.

Implementation of the Surveillance Testing Program at Unit 1 and control and execution of the Unit 2 Power Ascension Testing Program were good. This is contrasted with problems identified in the Unit 1 Inservice Inspection Program implementation and Unit 2 Surveillance Testing program implementation. These weaknesses stem from a lack of thorough planning and review, inadequate station and corporate management involvement and oversight, and insufficient followup of identified problems and known deficiencies. Further corporate management oversight and direction is needed to address problem areas such as Inservice Inspection and contractor activities.

Engineering and Technical Support staffs have been generally effective in resolving engineering concerns at both units when properly focused by station management.

As in the previous SALP for both units, performance in the areas of Security and Safeguards and Emergency Preparedness demonstrates a continued commitment to excellence and self improvement.

In the area of Licensing, efforts have been initiated to address past problems with commitment tracking, reporting of significant station events and to apprise the NRC of recent technical concerns. These areas continue to exhibit weaknesses and corporate management attention is needed to improve followup on potential safety issues and to provide timely and adequate submittals of Technical Specification amendments and reliefs.

Licensee training and qualification programs were generally effective. Corporate management attention is warranted in the area of licensed operator requalification training program implementation and documentation and the responsiveness to operator needs.

In summary, overall performance has shown limited improvement since the last assessment. As discussed above, performance has been inconsistent in that some areas have shown improvement while other areas exhibit problems similar to those addressed in the previous SALPs. The inability to provide for long-term, effective implementation of improvement programs along with instances of poor attitude, morale and communications is of concern to the NRC. These types of symptoms have historically resulted in significant performance problems if not appropriately addressed.

While we acknowledge your recent reorganization and efforts to focus management attention at the site, a corporate commitment is needed to support and foster cooperation and communication between departments. Additionally, clear standards of excellence and attention to detail are necessary to sustain corrective action programs.

B. Background

1. Licensee Activities

Unit 1

On October 16, 1987, an automatic scram due to an electrical pressure regulator failure ended an international record for continuous power operation of a Boiling Water Reactor (416 days). The reactor operated at near full power with only minor reductions for surveillance testing and rod pattern adjustments. The reactor was returned to power operations after a few days of corrective maintenance and another automatic scram occurred on December 7, 1987, while attempting to override an oscillating feedwater control valve. A December 11 unit startup was aborted after the turning gear malfunctioned and attempted to engage the rotor while the turbine was at 112 rpm. The unit was returned to power operations on December 14 and was manually scrammed on December 19, 1987, due to feedwater system problems.

The December 19 feedwater problems involved a severe system hydraulic vibration transient initiated by the mechanical failure of the 13A feedwater control valve. Investigation of feedwater system damage identified several damaged pipe supports and snubbers and a broken impeller blade on the shaft-driven feedwater pump. Further system inspection identified through-wall cracks in the suction piping to the No. 11 motor driven feedwater pump.

The Unit 1 forced outage to repair the feedwater system problems was extended after review of the 1986 ISI Program examination results identified missed visual examinations of reactor vessel flange stud bushings. After reactor vessel head disassembly, the licensee made a decision to commence the 1988 Refueling Outage early. Outage activities continued through the end of the assessment period.

Unit 2

During the months of February and March 1987 the licensee verified that all surveillance tests were satisfied for commencement of critical operations (Test Condition Heatup). In parallel with surveillance testing, work continued on the replacement of the ball-type main steam isolation valves (MSIVs) with conventional wye-pattern globe valves. The globe valves were installed and tested satisfactorily by April 1987.

Based on a request from the Regional Administrator, the licensee committed to a self-appraisal of all activities at Unit 2. On June 4, 1987, Niagara Mohawk established a Self-Appraisal Team (SAT) consisting of site supervisory level personnel who reported to senior management. The SAT was tasked with providing a report of their findings to the NRC staff prior to exceeding 50% of rated core power.

The reactor was taken critical for the first time on May 23, 1987, beginning Test Condition Heatup. During initial plant heatup, several problems developed leading to a plant shutdown on May 31, 1987. Numerous pipe supports and hangers required engineering evaluation and/or rework to correct thermal expansion deficiencies. Thermal stratification in feedwater lines downstream of Reactor Water Cleanup System (RWCU) return line penetrations caused higher than expected piping stresses. In early June, two unplanned reactor scrams occurred. A June 12 scram from 3% power was caused by the failure of a feedwater control valve. The second scram on June 15 from 2% power occurred during surveillance testing of the Redundant Reactivity Control System. Test Condition Heatup was eventually concluded with a planned reactor scram on June 27.

The full power operating license was granted to NMPC on July 2, 1987 after a unanimous decision by the NRC Commissioners.

Test Condition 1 (TC-1) began in July and was completed in the beginning of August 1987. During this period, a reactor scram occurred on July 11 due to an electro-hydraulic control tubing rupture, and the licensee shut down the unit on July 26 to comply with Technical Specifications (TS) due to high service water inlet temperature. TC-1 was completed with a successful remote shutdown from outside the control room.

Test Condition 2 (TC-2) began in August, but was interrupted by a shutdown initiated by licensee management in early September because of Standby Gas Treatment (SBGT) system surveillance testing concerns and the need to repair condenser tube leaks. The unit remained shutdown in September. TC-2 resumed in October and was completed by the end of the month. The final TC-2 test was the loss of offsite power test, resulting in a planned reactor scram. Two other scrams occurred during this period, one due to a high power excursion (October 1, 1987) caused by an inadvertent feedwater injection and the other (October 23, 1987) by a loss of condenser vacuum turbine trip.

The licensee presented the results of their SAT efforts to the NRC staff on September 21. The NRC staff also provided the licensee an interim assessment of their performance at this same meeting. Niagara Mohawk was subsequently authorized by the Regional Administrator to continue with Power Ascension Testing above 50% power.

Test Condition 3 (TC-3) began in early November 1987. The maximum power level reached was 67.2% before the unit was shutdown to allow for replacement of Grayloc couplings in the feedwater system. During this outage, the feedwater control valves were also reworked. In November, the A condensate storage tank ruptured due to a construction defect and was repaired. The plant was taken critical on December 22, but scrammed due to loss of condenser vacuum on December 26.

The unit was restarted on December 31 and TC-3 concluded in mid-January. During Test Condition 5 (TC-5) the unit was operating in natural circulation when on January 20 a scram occurred due to loss of feedwater flow. HPCS and RCIC initiated to restore level; however, the vessel subsequently was overfilled. The unit remained in cold shutdown in accordance with a January 21, 1988 NRC Confirmatory Action Letter requiring the Regional Administrator's permission to restart. The event and licensee corrective actions were reviewed by an Augmented Inspection Team, and the Regional Administrator authorized plant restart on February 1, 1988. TC-5 testing was completed during the second week of February 1988, and TC-6 was in progress by the end of this assessment period. The reactor achieved 100 percent of rated power on February 25, 1988.

2. INSPECTION ACTIVITIES

Unit 1 and 2

All the inspections performed during this SALP period are listed in Table 1. The inspection activities conducted over and above the routine inspections are discussed below.

Inspectors closely monitored the progress in resolving the problems with the Unit 2 ball-type MSIVs. When the licensee decided to replace these valves, additional inspections were conducted. These inspections included indepth review of newly designed electrical and mechanical systems for these valves and review of preoperational testing.

Based on the unsatisfactory packaging of a radioactive material shipment from Unit 1 to the Brunswick Nuclear Station, a special inspection of the circumstances leading to this event was conducted.

An Operational Readiness Team inspection was conducted at Unit 2 for two weeks in June 1987. This inspection was conducted to evaluate the licensee's readiness for a full power operating license.

A special inspection was conducted in September 1987 by the resident inspectors to examine the events leading to the failure to conduct surveillance testing of charcoal filters in the SBGT system trains at Unit 2.

A specialist team inspection was conducted during January 1988 to review the feedwater piping transient at Unit 1.

An Augmented Inspection Team of region based and Headquarters specialist inspectors was on site January 21-24, 1988, to review the circumstances leading to and licensee corrective actions for the January 20, 1988 Unusual Event at Unit 2 involving a reactor scram on loss of feedwater and subsequent vessel overfill.

C. Facility Performance Analysis Summary

Last Period Dates
Unit 1 6/1/85 - 10/31/86
Unit 2 2/1/86 - 1/31/87

Interim Assessment
Unit 2 6/4/87 - 9/4/87

Present Period Dates
Unit 1 11/1/86 - 2/29/88
Unit 2 2/1/87 - 2/29/88

Functional Area	Category Last Period	Category This Period	Trend
A. Operations			
1. Unit 1	2	2	--
2. Unit 2	2	2	Improving
B. Radiological Controls and Chemistry			
1. Unit 1	2	2	Declining
2. Unit 2	2	*	
C. Maintenance			
1. Unit 1	3	2	
2. Unit 2	N/A	*	
D. Surveillance			
1. Unit 1	2	2	
2. Unit 2 **	2	*	
E. Engineering and Technical Support			
1. Unit 1	N/A	2	
2. Unit 2	N/A	*	
F. Security and Safeguards			
1. Unit 1	1	1	
2. Unit 2	1	*	

	Functional Area	Category Last Period	Category This Period	Trend
G.	Emergency Preparedness			
	1. Unit 1	1	1	
	2. Unit 2	1	*	
H.	Licensing			
	1. Unit 1	1	2	Declining
	2. Unit 2	3	*	
I.	Training and Qualification Effectiveness			
	1. Unit 1	2	2	
	2. Unit 2	2	*	
J.	Assurance of Quality			
	1. Unit 1	3	3	
	2. Unit 2	2	*	
K.	Unit 2 Construction	2	N/A	
L.	Unit 1 Refueling and Outage Management	2	N/A	

N/A Indicates that the category was not included in the last or present period.

* Indicates that these areas are being combined for both units in the present period and one summary rating will be given.

** In the last period this area covered operational, surveillance and startup testing. In the present period this area includes surveillance and power ascension testing.

D. Unplanned Shutdowns, Plant Trips and Forced Outages

1. Unit 1

Date/Event	Power Level	Description	Cause	Functional Area
10/16/87 Automatic Scram	89%	High neutron flux scram: electrical pressure regulator servo valve malfunction.	See LER 87-14 Inadequate maintenance.	MAINT

Unplanned Shutdowns, Plant Trips and Forced Outages (Cont'd)

10/17/87 Automatic Scram While Shutdown	0%	Spurious IRM upscale trip due to noise.	See LER 87-15 Neutron monitoring system noise.	ENG/TS
10/19/87 Automatic Scram While Shutdown	0%	Spurious IRM upscale trip due to noise.	See LER 87-16 Neutron monitoring system noise.	ENG/TS
12/07/87 Automatic Scram	96%	Low reactor water level, failure of feed control valves to operate properly.	See LER 87-24 Inadequate troubleshooting.	MAINT
12/10/87 Automatic Scram while Shutdown	0%	Spurious IRM upscale trip due to noise.	See LER 87-25 Neutron monitoring system noise.	ENG/TS
12/11/87 Forced Shutdown Outage	2%	Forced shutdown to repair turbine turning gear.	Failure of turning gear control solenoid.	N/A
12/19/87 Manual Scram and Forced Outage	98%	Plant shutdown: Vibration in feed water piping due to failure of a feed control valve stem.	See LER 87-28 Valve fatigue failure.	MAINT

2. Unit 2

Date/Event	Power Level	Description	Root Cause	Functional Area
02/02/87 Automatic Scram while Shutdown	0%	Spurious low reactor water level signals.	See LER 87-10 Technician error.	SURV
02/07/87 Automatic Scram while Shutdown	0%	Spurious low reactor water level signals.	See LER 87-11 Detector sensitivity.	ENG/TS

Unplanned Shutdowns, Plant Trips and Forced Outages (Cont'd)

2. Unit 2 (Cont'd)

Date/Event	Power Level	Description	Root Cause	Functional Area
04/22/87 Automatic Scram while Shutdown	0%	Spurious low reactor water level signals.	See LER 87-20 Detector sensitivity.	ENG/TS
05/31/87 Forced Shutdown	1%	Shutdown to repair seismic restraints.	Thermal expansion	ENG/TS
06/12/87 Automatic Scram	3%	IRM upscale trip due cold water injection.	See LER 87-31 Valve linkage failure.	ENG/TS
06/15/87 Alternate Rod Insertion and Automatic Scram	2%	Spurious High Pressure ARI signal generated during testing.	See LER 87-33 Procedure deficiency.	SURV
07/11/87 Automatic Scram	4%	High pressure trip due to failure of EHC piping.	See LER 87-43 piping fatigue failure.	ENG/TS
07/26/87 Forced Shutdown	3%	Shutdown required by TS when Service Water temperature is greater than 76 degrees F.	See LER 87-44 Lake temperature too high.	ENG/TS
9/02/87 Voluntary Shutdown	5%	Management decision to shut down unit following SBGT surveillance testing concerns.	Inadequate management oversight.	OPS
10/01/87 Automatic Scram	2%	IRM Upscale Trip due to excess cold water injection power excursion.	See LER 87-58 Operator error.	OPS
10/23/87 Automatic Scram	36%	Turbine Trip due to loss of condenser vacuum.	See LER 87-64 Operator error. (Tagout improper)	OPS

Unplanned Shutdowns, Plant Trips and Forced Outages (Cont'd)

2. Unit 2 (Cont'd)

12/26/87 Automatic Scram	26%	Turbine Trip due to loss of condenser vacuum.	See LER 87-81 Piping fatigue failure.	ENG/TS
12/29/87 Automatic Scram while Shutdown.	0%	MSIV closure due to mispositioning of reactor mode switch.	See LER 87-82 Operator error and design problem.	OPS & ENG/TS
01/20/88 Automatic Scram	42%	Low reactor water level, due to loss of feedwater due to loss of instrument air.	See LER 88-01 Operator error.	OPS

IV. PERFORMANCE ANALYSIS

A. Operations (Unit 1 - 1147 hours, 17.5%; Unit 2 - 2160 hours, 32.9%)

1. Unit 1 Analysis:

During the previous assessment period, performance in this area had declined and was rated Category 2. Contributing to this assessment were operator complacency and informality in the conduct of operations. Housekeeping practices varied throughout the previous assessment period, indicating a lack of accountability for housekeeping at all levels. Assessment of the fire protection program implementation was good.

During this assessment period, operator technical competence showed some improvement. Indicative of this improvement was the operator contribution to an international record run set by the licensee for continuous power operation of a Boiling Water Reactor. On a few occasions, control room operators took prompt corrective action to correct conditions and prevent an impending reactor scram. Action taken by operators for the December 29 feedwater transient, resulting in a manual scram, were particularly noteworthy. This performance reflects a technically competent and experienced Operations staff.

Conversely, other operations related events demonstrate further examples of the complacency observed during the previous assessment period. On October 27, 1987, a Limiting Condition for Operation governing a recirculation loop isolation was violated because of a nonconservative licensee interpretation of Technical Specifications (TS). On another occasion, a TS Limiting Safety System Setting (LSSS) thermal limit was

violated because of an error by the Reactor Analyst responsible for performing the surveillance test. Although some licensed operators review the Reactor Analysts' thermal limit calculations and process computer printouts, they do not perform this oversight as a matter of routine to ensure compliance with TS requirements. On December 7, 1987, during troubleshooting activities, the operators attempted to manually override the 13B feedwater control valve because of its unstable operation. On the first attempt to manually override this valve, the 13A control valve did not respond to the automatic control signal and reactor vessel level began to decrease. The 13B blocking collar was quickly removed and vessel level was restored before reaching the vessel level low scram setpoint; however, without further investigation, a second attempt was made to manually override the 13B control valve resulting in a reactor scram. A more cautious and deliberate troubleshooting approach should have been taken after the initial attempt to override the control valve resulted in vessel level control problems.

Staffing in the Operations Department appears to be adequate. The use of overtime to cover special evolutions and to compensate for personnel absences was not excessive.

In general, operators are technically competent and knowledgeable of plant systems. This is evident in the low frequency of plant trips. They possess pride with regard to their abilities as an operating team; however, this sense of pride does not appear to extend beyond the Operations Department with respect to a spirit of cooperation and teamwork with other station departments. This sense of independence appears to isolate the operators from the rest of the station staff as reflected in the longstanding strained relationship between the Operations and Training Department, and the lack of responsibility Operations feels towards addressing Unit 1 housekeeping problems. These two concerns, in particular, have been known by station management for some time; however, no effective action has been taken to resolve this factionalism.

2. Unit 2 Analysis:

This area was rated Category 2 in the previous assessment. During that assessment period, the licensee completed the Preoperational Testing phase, was issued an operating license restricting maximum power to five percent of rated output and completed initial fuel load. The following weaknesses were noted: high number of events caused by personnel error; Senior Reactor Operators (SROs) familiarity with Technical Specifications and excessive administrative duties which detracted from their direct observation of station operations; lack of formality in the conduct of operations in the control room and the control room environment; and the Operations management was not providing meaningful oversight to ensure that problems were found and promptly corrected.

During this assessment period, the licensee had progressed through initial criticality and the majority of the Power Ascension Testing Program, Test Condition 6. The reactor had been operated to 100% of rated power. The delay between initial fuel load in November 1986 and initial criticality on May 23, 1987 was the result of a decision by NMPC to replace the ball-type main steam isolation valves (MSIVs) with conventional wye-pattern globe valves. This project was completed in early April 1987. At the conclusion of the period, the licensee was projecting Commercial Operation by the middle of March 1988.

A great deal of inspection effort was expended in this area to specifically determine the readiness of the licensee for full power operations and to determine the effectiveness of the various testing programs. Twenty-four hour coverage was provided by resident and regional based inspectors during the initial criticality phase. An Operational Readiness Team (ORT) composed of region based and resident inspectors was on site for two weeks after initial criticality to evaluate the licensee's readiness for a full power operating license. The ORT noted strengths in operator knowledge and sense of responsibility and control of unit operations. Weaknesses were identified in the control room environment, the control of operator aids, the lack of familiarity of operators with emergency equipment locations, the lack of emergency diesel generator operating logs, and the lack of an efficient method of tracking the operating time on special filter trains for the purpose of meeting Technical Specifications sampling requirements. Operations Department staffing level and use of overtime were considered to be adequate.

Personnel errors continued to occur this assessment period at a high rate. Most of these errors were due to inattention to detail and failure to follow procedures. Three reactor scrams on October 1 and 23, 1987 and January 20, 1988 can be attributed to inattention to detail. A lack of understanding of feedwater control system response caused reactor vessel overfeeding and a resultant reactor scram. Improper review of a feedwater pump tagout prior to authorizing maintenance resulted in a loss of condenser vacuum, a turbine trip and subsequent reactor scram. The tagout of one train of instrument air prefilters, without ensuring that the other train was operating, caused a loss of feedwater and resultant low reactor vessel water level scram and subsequent reactor vessel overfill.

Failure to comply with procedures was typified by four secondary containment isolations due to operators' errors in returning normal reactor building ventilation fans to operation in the required manner. Furthermore, violations were issued involving failure to follow operating procedures for the standby gas treatment (SBGT) and residual heat removal (RHR) systems, and failure to return forced circulation to the core within the TS required time interval. Although these examples were of minor safety significance, they indicate the need for station management to emphasize the proper use of procedures by the operating staff.

In addition, several required Technical Specification surveillances were missed by licensed operators. These missed surveillance tests were attributed to personnel error and lack of oversight by the CSO and Station Shift Supervisor (SSS), a licensed senior reactor operator. Station management needs to continue to ensure that the SSS and CSO are more actively involved to ensure completion of routine and off-normal plant evolutions.

Although there have been instances where licensed operators have not completely understood Technical Specifications (TS) during this period, they have been less frequent and do not point to a significant problem. When these instances have arisen, the licensee has taken proper action to clarify the TS and provide training to the operators. The use of the plant specific simulator to run power ascension tests prior to actual performance on the unit has benefited the operators. Simulator dry runs have helped to refine the procedures, to train the operators, and to familiarize the operators with the various TS and new licensing interpretations. A Technical Specification subject index has been compiled to assist the operators in ensuring all applicable TS for specific components or systems are complied with and a formalized system of TS interpretations has been implemented.

During this assessment period, the licensee established an emergency diesel generator operating log. This operating log assisted the licensee in discovering a misfiring injector before any damage to the diesel was experienced. The auxiliary operators who make rounds throughout the plant generally do not take operating logs on equipment. This is considered a weakness since valuable operating data which could be used to evaluate performance of equipment is missed.

The formality in the control room has improved. Early in the assessment period, inspectors noted instances when response to control room alarms had been slow and without proper followup. This was brought to the licensee's attention and annunciator response was observed to improve. During followup of the vessel overfill event in January 1988, it was noted that the assigned control room operators did not station themselves at one panel, but moved back and forth taking actions at different stations. This tended to complicate the overall operator response to the event necessary to stabilize the unit. Another weakness brought out by this event was that the Chief Shift Operator (CSO), a licensed reactor operator, did not always know what equipment was being tagged out of service so that he could anticipate plant response and properly evaluate alarms that were generated as a result of the tagouts. These weaknesses were appropriately addressed by the licensee through training and procedural changes.

Control room environment has improved. The SSS and CSO appear to have less of an administrative workload than during the last assessment period. The licensee has established more rigid controls for control room access which have led to a reduction in the number of people transiting through or lingering unnecessarily in the control room. The operator break area has been moved to outside the control room which also helps to reduce the control room traffic and noise. The licensee continues to evaluate additional control room enhancements.

Operations management has made substantial improvements this assessment period. Oversight of the day-to-day activities and staff workloads have improved. Better communications exist between supervision and the operating staff. Questions and problems raised by operators appear to be getting more attention. In addition, Operations management has begun tracking NRC concerns to ensure that appropriate actions are taken. A deficiency identified by the NRC early in the assessment period, involving inadequate charcoal filter surveillance testing tracking, prompted this initiative.

Operations Department involvement in Power Ascension Testing was well coordinated. Pretest briefings were professionally conducted with thorough discussions of expected plant responses and operator actions in the event of problems. Operators were genuinely interested in understanding the purpose of the tests and in conducting the tests to the best of their abilities. Control room personnel monitored plant parameters and proceeded cautiously with testing after assuring proper plant response. When cases developed where plant response was not as expected, the operators were observed to take proper corrective action.

3. Unit 1 and 2 Fire Protection Analysis:

Licensee implementation of the Fire Protection Program has shown improvement over this assessment period. The fire brigade consists of dedicated station personnel independent of the Operations staff. The fire brigade is manned around-the-clock and provides both units with firewatch patrols, continuous fire watches, fire alarm response and emergency medical response, if necessary.

Early in the assessment period, frequent personnel errors resulted in missed firewatch patrols. A violation was issued for ineffective corrective action because of their recurring nature and insufficient supervisory oversight. An extensive licensee review of the fire penetration surveillance program at Unit 1 was conducted this assessment period. This review resulted in the identification of several penetrations which were either improperly sealed or overlooked by an earlier program audit conducted by a contractor. Upon identification of these fire penetration deficiencies, the licensee took prompt compensatory action and initiated work requests to correct the problems. These fire protection program oversights were discovered as a result of a thorough program review and demonstrate the effectiveness of the present Fire Protection Program supervisory staff.

4. Summary

Unit 1 Operations department performance during this assessment period has shown little improvement. Operators, although technically competent and experienced, continue to demonstrate a complacent attitude with respect to overall station quality of operations. In contrast, the Unit 2 Operations staff has demonstrated significant improvement, although problems still arise due to operator error and inattention to detail. The Unit 2 Operating staff demonstrates a better station teamwork ethic than the Unit 1 operating staff. Corporate and station management needs to provide positive incentives to revitalize, motivate, and better integrate the Unit 1 Operations staff with other departments.

5. Conclusion:

Unit 1 Rating: 2

Unit 2 Rating: 2 - Improving

6. Board Recommendations:

a. Unit 1

NRC: None

Licensee: Management should evaluate the independence of operations from other departments.

b. Unit 2

NRC: None

Licensee: None

B. Radiological Controls and Chemistry (625 hours, 9.5%)

1. Analysis:

The Radiological Controls Programs at Nine Mile Point Units 1 and 2 were separately rated Category 2 during the previous assessment period. Significant weaknesses were identified last period at Unit 1 in the areas of supervisory and management oversight and control of on-going work, communications with workers, and the corrective action program for identified problems. Corporate support for the radiological controls program was also found to be weak last period. A Civil Penalty was issued early in this assessment period for breakdowns in the radiological controls program at Unit 1 identified last period.

During this assessment period, region based inspectors performed eight routine inspections at Units 1 and 2. One special inspection of a radwaste transportation incident at Unit 1 was also conducted. Resident inspectors reviewed this area on an ongoing basis.

a. Radiation Protection

The radiation protection program is common to both units and is implemented through two separate radiation protection groups reporting to a common manager. A reorganization, initiated last assessment period and completed early this assessment period, separated the Chemistry and Radiation Protection groups. The reorganization was initiated to provide for increased accountability and oversight of program activities. The new organization and personnel responsibilities are defined in appropriate station and site procedures. Additional staffing was hired to support Radiation Protection supervisors in overseeing ongoing work. However, observations during the recent outage indicated that the Radiation protection supervisor and management oversight of ongoing work continued to be inadequate, indicating a need for additional management attention to this area.

With the exception of the program to train radiation protection personnel in new procedures and procedure changes (a previously identified problem area) an adequately defined personnel training and qualification program is maintained and implemented. The General Employee Training Program is INPO certified. The Radiation Protection Technician Training Program is INPO accredited.

A number of significant breakdowns in the external exposure control program were identified at the end of the last assessment period during NRC review of an off-scale dosimetry incident associated with under vessel work at Unit 1. Review this assessment period found that the licensee did not address several of the previously identified concerns indicating the lack of timely and effective corrective action on NRC identified problems. Observations during the recent outage found that the licensee did not address the high radiation area surveillance problems previously identified. Also, control point technicians did not maintain adequate oversight of ongoing activities. Technician oversight of ongoing work was identified as a major concern last assessment period.

The Unit 2 radiation protection program was not significantly challenged due to the low radiation and radioactive material source term present. However, NRC review of significant radiological operations involving diving and installation of neutron sources at Unit 2 found licensee radiological controls to be of good quality.

The licensee normally provides adequate internal exposure controls for ongoing work. Intakes of airborne radioactive material are rare. Review of licensee corrective actions for several isolated incidents involving high airborne radioactivity last period indicated the licensee made a number of procedural enhancements to preclude recurrence. However, the procedural enhancements were not fully effective. Observations during the recent outage found that an installed engineering control system was inoperable and supplied breathing airlines were not protected from internal contamination and, as a result, were internally contaminated. Also, licensee procedural controls for sandblasting hoods were not in-place.

Reviews of contamination control this period indicated a number of weaknesses needing licensee attention. These weaknesses involved poor contamination control of personnel egressing the radiological controlled area (RCA) and poor contamination control of work requiring aggressive contamination control techniques. NRC review found RCA portal monitors out of calibration and out of service, portal monitors not being checked for operability, operability and calibration checks not being performed in accordance with procedures and poor frisking techniques by personnel. Also, the licensee had not implemented an effective radiological control program for hot particles resulting in two individuals sustaining skin exposures from hot particles. These weaknesses indicate, in part, a continued lack of corporate oversight of the program.

A generally well defined site and corporate ALARA program is in place. Standard ALARA techniques are routinely used to reduce personnel exposure to radiation and airborne radioactive material. Some program breakdowns were identified last period due to poor communications with work groups regarding ALARA requirements. Procedures were strengthened to correct identified concerns.

NRC observations during the recent Unit 1 outage identified examples of a lack of sensitivity to ALARA concerns in that station personnel were found unnecessarily waiting and working in radiation areas. Also, the ongoing job ALARA review program was not well defined. This made it difficult to follow ALARA performance and acquired exposure for jobs. In addition, observations of control rod drive work found personnel sustaining exposure due to malfunctioning old equipment.

The licensee took action to address NRC concerns identified last period regarding the quality of audits, surveillances and assessments to make them more performance oriented. However follow-up of findings was inconsistent. Corporate QA audit findings were found open for an extended period of time. For example, one finding dealing with establishment of a breathing zone air sampling program or justify exceptions, has been open since 1985. Additional corporate management attention is needed in this area.

b. Radioactive Waste Management and Effluent Control

The licensee has adequate oversight of radioactive waste management activities at both units. Positions were clearly established in the chemistry and solid radwaste areas. Audits were found to be thorough and comprehensive in scope. Procedures for control of radioactive effluents were very detailed and generally adequate. Procedures for control of solid radioactive waste in forms suitable for burial were also well detailed. The licensee maintains good capability for determination of quantities of radioactivity in its liquid and gaseous effluents as demonstrated by inter-comparison of measurements with the NRC Mobile Lab.

Some lapses in attention to timely review of monitor calibration by supervision and omission of vendor supplied tritium data on an effluent release record indicated a minor weakness in procedures at Unit One. At Unit Two, the Gaseous Effluent Monitoring System (GEMS) has been out of service since September 1987. The licensee has used an auxiliary sampling system since then to satisfied grab sample, flow estimate and reporting requirements of the Technical Specifications. The long period of time that the GEMS unit was out of service indicates a lack of site management attention in resolving this problem. Further licensee attention is warranted.

c. Non-Radiological Water Chemistry

The Unit 1 non-radiological water chemistry control program was determined to be adequate. Weaknesses were identified, including lack of a clear corporate statement of policy and lack of corporate technical overview of the non-radiological water chemistry program. Additional weaknesses were inadequate temperature control in sampling and measurement systems at Unit 1 and lack of determination of demineralizer capacities at Unit 2.

Procedures are provided for proper control of water chemistry. Operating methodologies were found responsive to minimizing crud induced localized corrosion (CILC) and microbially induced corrosion (MIC). Waste water recycling is conditional on Chemistry approval, and operating schemes for control rod drive (CRD) cooling water limits ingress of impurities. These are considered strengths in the program Administrative strengths in the program were identified including routine review by site supervision of water chemistry parameters.

Strengths were also noted in the licensee's program to monitor and control corrosion mechanisms at Unit 2 using zinc injection to mitigate radiation field buildup and temperature compensated in-line measurement systems.

d. Transportation

The programs for transportation of radioactive materials are separated; each unit has a dedicated staff and operations are independent. Both units' radwaste groups are clearly described in policy statements and positions are described including responsibility and authority. Procedures are generally thorough and consistent with regulatory requirements for shipments of waste for disposal. During the assessment period the Unit Two program was reviewed, but no shipments had been made to permit inspector assessment of the program implementation.

Comprehensive oversight activities were noted, indicating a strong management commitment to improving weaknesses found in this area in the last assessment period. Audits were comprehensive and surveillances on Unit One shipments were twice the committed frequency of ten percent. Similarly, corrective actions were thorough and met or exceeded commitments, indicating responsiveness to NRC initiated actions.

On May 15, 1987, two packages of equipment were delivered to a carrier for transport and use by another licensee. On arrival, radiation levels in excess of regulatory limits were found which resulted in violations of 49 CFR 173.441(a) and 10 CFR 71.5. The root cause for these was a lack of supervision and procedural weaknesses. The Unit One radwaste group was not directly involved in this evaluation. The licensee's corrective actions appear adequate to prevent recurrence, but were not fully implemented at the time of the routine transportation inspection, four months after the incident. This was an isolated case and does not reduce the overall adequacy of the licensee's transportation program.

e. Summary

In summary, the licensee made numerous procedural and training enhancements to address previously identified weaknesses and is making efforts to reduce exposure. However, observations indicate continuing problems with some previously identified concerns reflecting a need to further improve supervisory oversight of ongoing work activities, personnel attention to detail, and the corrective action program to ensure personnel are adhering to good radiological controls practices and procedure requirements. Additional attention is also needed in the area of contamination control and ongoing job ALARA reviews. Improvement is needed in the Unit 1 non-radiological water chemistry area as it relates to radiation field buildup and improvement in the operation of the GEMS System at Unit 2 is warranted.

2. Conclusion

Category 2 - Declining

3. Board Recommendations

NRC: None

Licensee:

- Review and improve oversight of on-going radiological work activities.
- Make improvements in non-radiological chemistry area for Unit 1.
- Restore GEMS to operation and conduct an integrated system test for Unit 2

C. Maintenance: (718 hours, 10.9%)

1. Analysis:

Maintenance was rated Category 3 for Unit 1 and was not assessed for Unit 2 in the previous assessment period. In the previous period, the following weaknesses were observed at Unit 1: failure to identify repetitive equipment failures; failure to determine the root cause of failures; forced outages or reactor scrams caused by personnel errors because of inadequate control of maintenance or post-maintenance testing; and identified problems were handled at too low a level in the organization, as a result, management was not aware of many of the problems in the plant.

Corrective and preventive maintenance is performed by the Electrical and Mechanical Maintenance, Instrumentation and Controls and Computer Departments. Each unit has an essentially dedicated maintenance staff. The respective department Unit Supervisors report to both the Unit Superintendent and their respective Department Superintendent who oversees maintenance on both units. Because of this commonality, the category of Maintenance has been combined for both units this assessment period.

Licensee management involvement in assuring quality was evident this assessment period. Examples of station and corporate management involvement included their efforts to computerize the Work Request System, to incorporate craft training requests into the training schedule, and to expand the monthly safety meetings to include a detailed review of a different procedure each month. The maintenance staff was adequate, well equipped, knowledgeable and trained to support the maintenance activities of the plant.

During the beginning of this assessment period, repetitive equipment failures occurred due to inadequate initial root cause determination or inattention to detail in implementing maintenance. Significant examples included:

-- A Unit 1 emergency diesel generator (EDG) tripped on low lube oil pressure three times in nine months. A modification to the EDG was eventually made that was similar to a modification previously performed on the same type of EDG at Unit 2 to correct a similar problem. This example also illustrates the need to strengthen the interface between the two units.

-- A Unit 1 liquid poison pump motor burned out after repeated attempts to troubleshoot the motor. The cause was subsequently determined to be in the pump motor breaker. The cause was the same as a 1986 breaker failure.

-- Unit 1 experienced a reactor scram due to sticking feedwater control valves. The cause of this control valve problem was not identified. Later in the same month, a feedwater piping transient and resultant manual reactor scram occurred as a result of a castastrophic failure of the same feedwater control valve.

These examples indicate that more attention should be given to equipment failure root cause determinations and that licensee efforts to improve in this area have not been totally effective.

The number of Engineered Safety Feature initiations due to personnel errors during the performance of maintenance has decreased this assessment period. Licensee corrective actions in this area including closer oversight of maintenance activities by the Operations staff and additional lessons learned training of maintenance personnel appear to be effective.

During the assessment period, examples of not performing activities in conformance with approved procedures were again identified. These examples included the failure to use a special packing tool required by procedure, the failure to properly tagout equipment before maintenance as required by the procedure, and the failure to notify the control room when battery corrosion was found during maintenance, as required by procedure. Although actions have been taken to improve compliance with approved procedures, this area needs further management and station employee attention.

During the assessment period, the NRC raised questions about the adjustment of valve packing and the appropriate documentation of this maintenance with respect to ensuring proper post-maintenance testing on safety related valves. The failure of the licensee to consistently use Work Requests to document this maintenance was identified as a weakness due to the potential for adversely effecting the operation of a safety system. The licensee committed to use Work Requests for future packing adjustments to ensure proper post-maintenance testing and review by the Engineering staff.

-- A Unit 1 emergency diesel generator (EDG) tripped on low lube oil pressure three times in nine months. A modification to the EDG was eventually made that was similar to a modification previously performed on the same type of EDG at Unit 2 to correct a similar problem. This example also illustrates the need to strengthen the interface between the two units.

-- A Unit 1 liquid poison pump motor burned out after repeated attempts to troubleshoot the motor. The cause was subsequently determined to be in the pump motor breaker. The cause was the same as a 1986 breaker failure.

-- Unit 1 experienced a reactor scram due to sticking feedwater control valves. The cause of this control valve problem was not identified. Later in the same month, a feedwater piping transient and resultant manual reactor scram occurred as a result of a castastrophic failure of the same feedwater control valve.

These examples indicate that more attention should be given to equipment failure root cause determinations and that licensee efforts to improve in this area have not been totally effective.

The number of Engineered Safety Feature initiations due to personnel errors during the performance of maintenance has decreased this assessment period. Licensee corrective actions in this area including closer oversight of maintenance activities by the Operations staff and additional lessons learned training of maintenance personnel appear to be effective.

During the assessment period, examples of not performing activities in conformance with approved procedures were again identified. These examples included the failure to use a special packing tool required by procedure, the failure to properly tagout equipment before maintenance as required by the procedure, and the failure to notify the control room when battery corrosion was found during maintenance, as required by procedure. Although actions have been taken to improve compliance with approved procedures, this area needs further management and station employee attention.

During the assessment period, the NRC raised questions about the adjustment of valve packing and the appropriate documentation of this maintenance with respect to ensuring proper post-maintenance testing on safety related valves. The failure of the licensee to consistently use Work Requests to document this maintenance was identified as a weakness due to the potential for adversely effecting the operation of a safety system. The licensee committed to use Work Requests for future packing adjustments to ensure proper post-maintenance testing.

A long standing concern this assessment period has been the existing Technical Specifications (TS) for Unit 2 Emergency Batteries which allow no corrosion on bus bars or connectors. Following NRC identification of rapid corrosion buildup on the batteries, the licensee has taken adequate measures to increase the surveillance on these batteries to ensure proper corrective maintenance, when required. A TS change is being proposed to make the battery corrosion requirement less stringent. Maintenance management responsiveness to this concern was adequate.

The licensee has established a Work Control Center at Unit 1. The Work Control Center was initiated to allow better tracking and coordination of outage maintenance activities and appears to be functioning well. For example, the identification, tracking and resolution of problems encountered in the area of Inservice Inspection has recently improved. This indicates that station management has initiated steps to improve coordination of outage maintenance activities. In addition, Quality Assurance and Quality Control overview of maintenance activities was observed to be appropriate.

In summary, the low number of maintenance related reactor scrams and unplanned shutdowns for both units indicates improvement this assessment period. Improved first line supervisor oversight and higher visibility and interaction of more senior maintenance management in the field was noted. A significant backlog of maintenance related Work Requests was observed; however, this backlog does not indicate any immediate impact on safe plant operation. Further station management atttention in this area is needed to reduce the backlog. Root cause evaluations and attention to detail in maintenance implementation continue to be a weakness, but show signs of improvement. The licensee must continue emphasis in the maintenance at both plants due to the age of Unit 1 and the inexperience of the maintenance staff with the new systems at Unit 2.

2. Conclusion:

Rating: 2

3. Board Recommendations:

NRC: None

Licensee: None

D. Surveillance (Unit 1 - 163 hours, 2.5%, Unit 2 - 841 hours, 13.6%)

1. Analysis:

a. Unit 1

During the previous assessment period, this area was evaluated as Category 2. The surveillance testing program was judged to be adequate; however, an increase in personnel errors indicated a complacent attitude toward routine surveillance activities. This increase in surveillance related problems was also attributed to insufficient coordination of testing during unit outages and unusual evolutions.

During this assessment period, there has been a decline in missed surveillances, with the exception of the Fire Protection Program penetration surveillance testing problems discussed in the Operations section, and few surveillance related difficulties. One reactor scram did occur during surveillance testing, but the scram was caused by an equipment failure in the system being tested. The reduction in missed surveillance tests was primarily due to the use of a computer-based tracking system discussed in the previous SALP. The computer tracking system is only an aid to surveillance scheduling and as a result the licensee is still vulnerable to surveillance tests being performed outside the required interval. Two examples of surveillance tests being performed outside the allowable (325%) interval were identified and reported by the licensee to the NRC during this assessment period (LER No. 87-04 and 87-11). Personnel error was the cause for both these events; however, they appear to be isolated instances.

As discussed in the Unit 1 Operations section, a reactor analyst failed to recognize that a thermal limit (Maximum Total Peaking Factor) was in excess of the specified limit. No independent review of the surveillance test results was conducted by either a licensed operator or another reactor analyst until 34 hours later. The lack of a method to ensure prompt independent review of TS (thermal limit) surveillance tests results is a weakness.

Inservice Inspection

In the area of Unit 1 Inservice Inspection (ISI), several weaknesses were identified this assessment period resulting in escalated enforcement action. These weaknesses involve failures to comply with the ISI Program requirements, failure to elevate ISI discrepancies to station management, and inadequate management involvement and support of ISI activities. This topic is discussed further in the Assurance of Quality section.

It was determined that the site procedure for ISI Certification of visual examination personnel was not in compliance with ANSI-N45.2.6 as required by ASME Section XI. The procedure could have permitted an individual to become a certified Level I and Level II visual examiner with substantially less experience than that required by ANSI 45.2.6. Although the personnel performing Level I and Level II examinations were determined to be knowledgeable, there is a need for increased site and corporate management effort to assure requirements are correctly defined in procedures and properly implemented.

b. Unit 2

During the previous assessment period, this functional area was rated Category 2. The previous assessment period included observations of Preoperation, Surveillance and Startup Testing. The weaknesses identified during the previous assessment indicated a lack of station management involvement early in the startup and preoperational test programs and an initial lack of adequate review of the surveillance testing program. Later in the assessment period, the station management became more active in the review and scheduling of testing and significantly minimized testing conflicts and potential problems. During this assessment period, the areas of Power Ascension Testing (previously referred to as Startup Testing) and routine Surveillance Testing were reviewed.

Surveillance Testing

During this assessment period, several missed surveillance tests were identified: firewatch patrols were missed because of poor communications and supervisory oversight; the licensee failed to perform several TS required shiftly surveillance tests because of inattention to detail and program deficiencies; the licensee failed to perform APRM upscale trip and rod block surveillance checks because of inadequate review of a first-time mode change requirement; the licensee identified that the SBGT system charcoal filter sampling requirement had been exceeded due to procedural inadequacies, personnel error and inadequate corporate and station management oversight; and, the licensee determined that one of the drywell personnel air lock door equalizing valves was not being properly leakage rate tested because of a personnel error and inadequate design.

The missed surveillance tests discussed above indicate inattention to detail and insufficient supervisory oversight. The corrective actions taken for these deficiencies were determined to be comprehensive. The SBGT system surveillance testing violation was also indicative of inadequate corporate and station management oversight and followup of a NRC previously identified problem area.

Numerous unanticipated events occurred during the performance of surveillance testing this assessment period. These events were generally the result of either test procedure inadequacies or personnel errors.

Procedural problems caused the following: a containment isolation on 8/13 due to electrical protection assembly testing; a containment isolation on 2/2 due to reverse flow check valve testing; main steam isolation valve isolations on 2/8 and 9/9 due to turbine stop valve testing; and an alternate rod insertion on 6/15 due to Redundant Reactivity Control System testing. These test procedure deficiencies were of a power ascension nature and were not considered to be a continuing problem area.

Personnel errors caused the following: secondary containment isolation and automatic SBGT system actuation while testing ventilation radiation monitors; secondary containment isolations and SBGT system actuations due to inadequate testing coordination; a primary containment isolation due to lifting the wrong test lead; primary containment isolations due to failure to follow the test procedure; and, a secondary containment isolation due to accidentally bumping a trip relay. These personnel errors collectively indicate a need for more attention to detail. Some of these events are of repetitive nature and indicate corrective actions to prevent recurrence were not fully effective.

During the investigation into why an MSIV did not close at Unit 2 during surveillance testing, the licensee discovered a failed J10 Gould AC relay. Subsequent to finding the failed relay, the licensee performed a systematic inspection of J10 relays and found 16 more cracked relays in safety related panels. The failure mode was identified and corrected prior to replacing the 16 cracked relays. The licensee's approach to resolving this safety related technical issue was thorough and systematic, and effectively identified and corrected the conditions leading to the failure. Licensee management involvement in this matter ensured that quality was maintained. A review of the same type relays was conducted at Unit 1 to ensure no similar problems exist. None were found.

Inspector observation of surveillance testing generally found that operators and technicians performing the tests were knowledgeable and cautious in the conduct of the testing. The control room was typically contacted before the tests started for approval and at the conclusion of the testing to convey test results. Followup of testing problems has generally been adequate. Supervisors were knowledgeable of the work being performed and utilized a master schedule to track the completion of specific surveillance tasks. Operations personnel oversight and control of the multitude of surveillance tests performed this assessment period was generally effective.

Power Ascension Testing

During the previous assessment, station management involvement in the Preoperational Testing phase was lacking. During this assessment period, the management oversight of the Power Ascension Testing Program has improved considerably and has been generally effective in resolving problem areas.

Station management overview of the day-to-day power ascension testing has generally been effective. However, early in the testing program daily planning meetings to obtain plant status and to coordinate further testing activities were not totally effective. Problems were encountered in assembling accurate information on equipment status. With the exception of the Operations Department representatives, attendees were frequently ill-prepared. Available information on backshift and weekend activities was typically sketchy and inaccurate. This did not result in any safety concerns, but hindered progress and scheduling.

To improve the daily planning meetings, the licensee revised the daily status report to include more pertinent information and rescheduled the planning meeting to one hour later (9:30 a.m.) to ensure better attendee preparation. Towards the end of the assessment period, the efficiency of the daily planning meetings appeared to have improved and department representatives seemed better prepared.

Numerous equipment problems have been encountered during power ascension testing (for example: reactor water cleanup pump seal failures, offgas flow problems, and electrohydraulic control system vibration). Management attention has been clearly focused on the safety implications of these problems and the plant staff has proven capable in addressing them. However, early in the assessment period, the plant staff's efforts in resolving these problems were hampered by the lack of availability of spare parts, poor communication and coordination between station departments, and a lack of adequate Engineering Department support (for further discussions, see the Engineering and Technical Support section). During the latter half of this assessment period, Engineering staff support and station communications improved.

Overall, the Power Ascension Test Program has been deliberately paced and well implemented. All testing witnessed was well organized and properly controlled. Prior to testing, the General Electric Company Shift Test Supervisors and licensee Station Shift Supervisors (SSS) held briefings to discuss the procedure, anticipated plant response, and review actions required in the event of problems. In addition, many of the major power ascension tests were run on the unit simulator and operators gained valuable training and familiarity with the tests as a result. During testing, GE test engineers and Operations personnel carefully monitored plant parameters and proceeded cautiously with testing after assuring proper plant response. SSSs effectively controlled the testing and maintained the proper control room atmosphere.

Selected power ascension test results packages were reviewed and found complete and clearly documented. The testing results were relatively good with a reasonable number of test exceptions generated. The test exceptions were properly documented and appropriate plans were formulated to resolve them. The licensee's results review process progressed smoothly. Technical review of the test results appeared thorough and the SORC reviews were adequate. In addition, Quality Assurance Department participation in the oversight of the Power Ascension Testing Program was evident and effective in ensuring compliance with the program.

The licensee's initiative to perform a trial run of the loss of offsite power test in cold shutdown was beneficial in that it identified several minor problems that could have unnecessarily complicated the actual test if performed at power. It provided a valuable training opportunity and allowed for refinement of the test procedure prior to performance of this high profile test. The actual loss of offsite power test was conducted extremely well, due to the management initiatives to conduct a practice run. During the test a significant fraction (more than half) of the Station Shift Supervisors, as well as the Unit and Operations Superintendents participated or observed plant response. This was noted as another valuable training opportunity and indicative of management involvement in the testing program.

In summary, the surveillance testing program at Unit 1 has been effectively implemented with only minor problems having been identified this assessment period. The implementation of the Surveillance Testing Program at Unit 2 has been adequate during this initial phase of power operations and station management oversight and Unit 2 staff involved in the Power Ascension Testing Program have demonstrated generally effective coordination and execution of the program. However, the numerous problems which have been encountered such as the Unit 2 SBGT system missed surveillance testing and Unit 1 ISI Program problems indicate weaknesses in the following areas: thorough planning and daily review; close station and corporate management involvement, and followup of problems and deficiencies encountered in the execution of these surveillance programs.

2. Conclusion:

Rating: 2

3. Board Recommendations:

NRC: None

Licensee: Strengthen corporate management oversight of the surveillance program

E. Engineering and Technical Support (418 hours, 6.4%)

1. Analysis:

This area was not evaluated as a separate functional area during the previous SALP period for either unit, although the engineering services provided to support the completion of construction activities at Unit 2 were considered in the overall assessment of the Construction Area in the last Unit 2 SALP. During this current SALP period, engineering and technical support to the station staff was assessed based upon the services provided to the plant maintenance and modification processes and the Operations staffs for the continued operation of both units.

The corporate Engineering staff is administratively divided into two groups, one for each unit. Each group has a supervisory staff to coordinate the different engineering disciplines. This supervisory staff reports to a common engineering management. The site Technical Support organization is similarly organized, but is located on site and reports to the Station General Superintendent. The majority of the Engineering personnel for Unit 2 are also located on site, whereas, the majority of Unit 1 Engineering staff is located at the Nuclear Division Headquarters approximately 35 minutes from the site.

The licensee continues to make improvements in their Engineering organization geared towards improving engineering support of the station. The various engineering discipline managers have been given the authority to approve outside consultant services, should the need arise. This authority enhances the ability of the Engineering Department to arrange and provide engineering expertise not available in-house at short notice.

The licensee has also established a comprehensive training policy for individuals at all levels in the organization. The permanent training staff is supplemented by individuals from various disciplines assigned as instructors. If required, consultants are retained for specific courses. A review of reportable events for this assessment period does not indicate any training deficiencies.

Vendor or contractor engineering and work activities are controlled by a responsible licensee project engineer. This individual is responsible for monitoring all aspects of the job including quality assurance and control, with the assistance of the station QA organization. This facet of the work activity is particularly important to ensure that the licensee is being provided a good product. The following are examples where the licensee has not had good control over contractors this assessment period:

E. Engineering and Technical Support (418 hours, 6.5%)

1. Analysis:

This area was not evaluated as a separate functional area during the previous SALP period for either unit, although the engineering services provided to support the completion of construction activities at Unit 2 were considered in the overall assessment of the Construction Area in the last Unit 2 SALP. During this current SALP period, engineering and technical support to the station staff was assessed based upon the services provided to the plant maintenance and modification processes and the Operations staffs for the continued operation of both units.

The corporate Engineering staff is administratively divided into two groups, one for each unit. Each group has a supervisory staff to coordinate the different engineering disciplines. This supervisory staff reports to a common engineering management. The site Technical Support organization is similarly organized, but is located on site and reports to the Station General Superintendent. The majority of the Engineering personnel for Unit 2 are also located on site, whereas, the majority of Unit 1 Engineering staff is located at the Nuclear Division Headquarters approximately 35 minutes from the site.

The licensee continues to make improvements in their Engineering organization geared towards improving engineering support of the station. The various engineering discipline managers have been given the authority to approve outside consultant services, should the need arise. This authority enhances the ability of the Engineering Department to arrange and provide engineering expertise not available in-house at short notice.

The licensee has also established a comprehensive training policy for individuals at all levels in the organization. The permanent training staff is supplemented by individuals from various disciplines assigned as instructors. If required, consultants are retained for specific courses. A review of reportable events for this assessment period does not indicate any training deficiencies.

Vendor or contractor engineering and work activities are controlled by a responsible licensee project engineer. This individual is responsible for monitoring all aspects of the job including quality assurance and control, with the assistance of the station QA organization. This facet of the work activity is particularly important to ensure that the licensee is being provided a good product. The following are examples where the licensee has not had good control over contractors this assessment period:

-- The Unit 1 RBCLC heat exchangers are being replaced during the 1988 Refueling Outage. The contractor did not have an approved Appendix B program, but adequate oversight of the heat exchanger fabrication process was observed by the licensee's QA organization at the contractor's facility. Work activities on site were not well controlled and the station QA group has had to place a Stop Work Order on the job until deficiencies are properly resolved. This indicates good QA oversight, but poor engineering planning and coordination with the contractor.

-- Following the January 20 reactor scram at Unit 2, the licensee discovered that calculations provided by two separate contractors were in error for reactor vessel level and condensate storage tank level transmitter setpoint calibrations. It is apparent that the licensee did not properly review those contractor's calculations to ensure that they were correct.

Although there were problems identified this assessment period with products and services provided by contractors, the licensee has demonstrated that their oversight of contractors has improved in certain areas. For example, the QA oversight of the RBCLC heat exchanger replacement at Unit 1 and the replacement of the main steam isolation valves at Unit 2. In contrast, the Engineering support provided to the Unit 1 Inservice Inspection (ISI) Program and the principal contractor for this program was observed to be poor.

At the conclusion of the Unit 1 Refueling Outage in July 1986, Corporate Engineering was forwarded the results of a failed hydrostatic test on one of the reactor building closed loop cooling (RBCLC) heat exchangers. This deficiency was not reviewed and dispositioned by Engineering until November 1986. In September 1987, additional outstanding ISI examination results from the Unit 1 1986 outage were finally reviewed by Engineering, some of which involved safety related systems. As of the end of this assessment period, some of the Engineering dispositions of these ISI examinations were still in doubt and being reviewed. These problems illustrate gross inadequacies in the daily support and program oversight of ISI at Unit 1 by the Engineering and Technical Support staffs.

To resolve major system design and operating problems identified during this assessment period, the licensee implemented an Engineering Task Force approach. This approach assigned one engineer to be the focal point of the problem identification and solution process, and the coordinator of all engineering resources for the task. The task force approach was used several times this assessment period and examples are discussed below:

-- During initial Power Ascension testing at Unit 2, operating problems with the Offgas System were encountered. A task force was formed to evaluate the system malfunctions. The team was able to identify numerous system design problems and formulate proper engineering modifications in a short period of time. Although the task force was able to resolve the system problems expeditiously, it was approximately two weeks from initial discovery of system problems until Engineering became involved and walked down the system to start their evaluation. Engineering responsiveness to this operating problem was slow, but their resolutions were well-engineered.

-- In December 1987, a Unit 1 manual scram was initiated due to feedwater system vibrations. The NRC staff had numerous questions regarding the event and in order to coordinate the information gathering and evaluation, a task force was established. Frequent discussions held between the resident inspectors and Task Force members resulted in the inspectors often telling the Task Force members of information pertinent to the feedwater transient evaluation that they were not already knowledgeable of or briefed on by the station staff. This indicated that the Engineering Task Force may have not been fully supported by the Unit 1 staff. At the conclusion of this assessment period, the NRC was awaiting the licensee's final report on this event. A NRC team inspection conducted a preliminary review of the licensee's event assessment and determined it to be adequate.

The Engineering Task Force approach has proven to be an effective tool in identifying the root cause of system design problems and coordinating the overall engineering and technical staff efforts. As mentioned above, the interface between the station and the site corporate engineering staffs needs to be strengthened. Observations made at Site Operating Review Committee (SORC) meetings and Daily Planning meetings indicate that the interface between the station and engineering staffs lacks a true spirit of cooperation and are sometimes openly antagonistic. For example, Engineering representatives at the Unit 2 Daily Planning meetings, early in the assessment period, were often ill-prepared for providing the status of engineering work activities and appeared to be reluctant to assume any additional assignments. This situation persisted for some time before action by either station or corporate management was taken to improve this strained relationship.

Many automatic Engineered Safety Feature (ESF) actuations this assessment period have been caused by engineering design deficiencies. These repetitive actuations indicate that Engineering resolutions to these

design problems have been either ineffective or slow in being addressed. For example, the sensitivity of the Rosemont 1153 differential pressure transmitters has been a problem since identified in the last Unit 2 SALP period. Because of the lack of adequate dampening in the transmitter signal processing circuit, any short duration pressure spike due to hydraulic or mechanical shock typically results in a transmitter trip signal. Until resolution of this problem with the installation of capacitors in the trip circuitry to dampen the transmitter response, numerous automatic ESF actuations and unnecessary challenges to safety systems occurred. Similarly, numerous reactor water cleanup system isolations have occurred because of apparent differential pressure flow transmitter problems. Engineering has attempted several modifications to the location and physical orientation of these differential pressure transmitters with some success. Spurious automatic isolations have been less frequent towards the end of the assessment period.

The NMPC Engineering staff support of the prototype testing of the Unit 2 ball-type MSIVs prior to the decision to replace the valves was good. During the time the prototype valve was being tested, the licensee developed contingency plans for valve replacement with conventional wye-pattern globe valves. Because of this preplanning, once the decision was made to proceeded with valve replacement, the valve changeout progressed smoothly.

A dedicated project organization was created to control all aspects of the removal and installation of the new valves. The organization was staffed with competent managerial, technical, construction and Quality Assurance personnel. The organizational responsibility and authority were well defined and constant communication was maintained with the subtier work force, management and engineering. The effective communication network aided in resolving in-process problems that developed. There was an observed lack of supervisory oversight and Quality Control support in the field as the project began. This observation was brought to station management attention and was quickly corrected.

Although there was a lack of aggressiveness in resolving the control and power supply problems and difficulty in completing welding activities, the overall engineering and installation of the new MSIV's was well controlled, of high quality and indicative of management's involvement in assuring quality work.

Weaknesses in the design change/modification process were identified in the previous assessment period and subsequent program improvements and enhancements have been implemented. Notable enhancements in the modification process included: more timely revisions and distribution of critical drawings; more field involvement by Engineering personnel; and, increased involvement and overview by QA/QC. However, further site and corporate management attention is required to ensure that the activities related to installation and testing are also effectively implemented.

The Technical Support staff continues to improve in their ability to investigate station events and document their findings and corrective actions in Licensee Event Reports. This group is also involved in the final decision of reportability of events. Their determinations were generally conservative.

In summary, the licensee's Engineering and Technical Support staffs are generally effective in resolving engineering concerns at both units. There was a notable improvement in design change activities, this assessment period. Engineering involvement in the resolution of ISI Program concerns was inadequate. Management attention is needed in the area of contractor oversight to identify and correct problems within the Engineering organization and to improve the station-to-Engineering Department interface.

2. Conclusion:

Rating: 2

3. Board Recommendations:

NRC: None

Licensee: None

F. Security and Safeguards (256 hours, 3.9 %)

1. Analysis:

During the previous assessment period, the licensee's performance in this area was Category 1. This rating was influenced largely by the licensee's well-planned integration of Unit 1 and Unit 2 into a combined site security program, a demonstrated thorough understanding of NRC Security objectives and a very good enforcement history. During this assessment period, three routine security inspections (one announced and two unannounced) plus one special security inspection were performed by region-based inspectors. Routine inspections by the resident inspectors continued throughout the period. One licensee identified violation occurred during the assessment period.

Corporate management interest in the security program remained evident during this assessment period by the continued on-site presence of an effective and knowledgeable Security Manager who reports directly to the Corporate Senior Vice President for Nuclear Generation. The Security Manager and his supervisory staff are well trained and qualified security professionals who are vested with the necessary authority and discretion to ensure that the security program is carried out effectively and in compliance with the NRC regulations. The Security Manager is also

actively involved in the Region I Nuclear Security Association and other groups engaged in addressing nuclear security matters.

Security systems and equipment are state-of-the-art and are tested and maintained by a group dedicated to that effort. Malfunctions are promptly corrected and a preventive maintenance program is in place to enhance the reliability of systems and equipment. This is indicative of the licensee's interest in maintaining a quality program.

The annual audit of the security program, performed by the licensee's Safety Review and Audit Board, was comprehensive in scope and depth. Corrective actions on deficiencies identified during the audits were prompt and effective with adequate follow-up to ensure their proper implementation. Additionally, the licensee established, at its own initiative, a Commitment to Excellence program which includes a daily audit or surveillance of a certain aspect of the security program and encourages members of the security force to identify and report potential problem areas. This is further evidence of the licensee's interest in a quality program.

Review of the licensee's security event reports and reporting procedures found them to be consistent with the NRC's regulations (10 CFR 73.71). There were five security event reports submitted during the assessment period. Two of these were discussed in the previous SALP report for Unit 2. The other three involved a computer software problem, an obscure breach in a vital area, and a failure to recognize a defective perimeter intrusion alarm. The licensee took prompt and effective compensatory and/or corrective measures for each event. The event reports submitted to the NRC were prompt, clear, thorough, and indicative of careful management review of the event and the report. The licensee has also developed an extensive matrix to be used as guidance in determining the level of reportability for events.

Staffing of the proprietary security force continues to be adequate as evidenced by a limited use of overtime. The security force training and requalification program is well developed and administered by a full time, experienced staff, under the direction of a training supervisor. Facilities for training and requalifications are available on site or on adjacent owner controlled property. These facilities are well equipped and well maintained. Contingency drills are conducted at least once each month. These are effectively used for training purposes and receive a critique that is fed back into the formal training program. The licensee is actively pursuing a program for participation of the operations organization during exercises of contingency events which could have an effect on plant operation.

Security plan changes submitted during the assessment period were clear and concise, and adequately described in a summary transmitted with each change. Pages were clearly marked to facilitate review by the NRC and the changes reflected a thorough understanding of NRC requirements. The

licensee's safeguards licensing function is adequately staffed by experienced personnel who are knowledgeable of NRC program objectives and the staffing level is indicative of the licensee's commitment to maintaining an effective and high quality program.

In summary, the licensee continues to implement a very effective security program that goes beyond compliance with regulatory requirements and security plan commitments. In addition, the licensee continues to implement innovations, such as the Commitment to Excellence Program, which are indicative of the licensee's intention to pursue a high quality security program.

2. Conclusion:

Rating: 1

3. Board Recommendations:

NRC: None

Licensee: None

G. Emergency Preparedness (182 hours, 2.8 %)

1. Analysis:

During the previous assessment period, licensee performance in this area was rated as a Category 1 for both units. No weaknesses were identified.

The basis of the assessments for this SALP period include observation of the annual partial-participation emergency exercise and review of Emergency Plan and Emergency Procedures revisions by the NRC staff. In addition, on January 20, 1988, two events occurred (one at each unit) which required implementation of the Emergency Plan. Both events were classified as Unusual Events.

The licensee's execution and participation in the annual exercise demonstrated thorough planning and a strong management commitment to maintaining a high degree of emergency preparedness. Emergency response personnel were observed to be knowledgeable in their duties and in use of Emergency Preparedness Implementing Procedures, a reflection of a high level of training. Only minor deficiencies were identified during the exercise. The licensee conducted an adequate critique of the exercise by identifying deficiencies in need of corrective action. Deficient areas identified during previous exercises were not repeated.

The licensee acted promptly and correctly to the two Unusual Events which were declared during this assessment period. Assessment actions,

notification of offsite authorities and communication among key responders were proper. During the first event, the licensee effectively handled an actual medical emergency involving the transport of a contaminated and injured Unit 1 employee to the local hospital. Response to the second event, involving a loss of instrument air resulting in a reactor scram and vessel overfill, was also prompt and correct.

The licensee has adequate full-time onsite and corporate staff who are assigned to maintain the Emergency Preparedness Program. Emergency Response Facilities (ERF) are dedicated and have been well maintained throughout the period. These facilities include the Emergency Operations Facility, Technical Support Center, Operations Support Center and Joint News Center.

In summary, the licensee continues to exhibit the qualities necessary to ensure efficiency in their Emergency Preparedness Program. Training of all levels of personnel is extensive. It is evident that the management attention and commitment to emergency preparedness has resulted in strong performance in all areas of the emergency response organization.

2. Conclusion:

Rating: 1

3. Board Recommendations:

NRC: None

Licensee: None

H. Licensing

1. Analysis:

During the previous assessment periods, this area was rated Category 1 for Unit 1 and Category 3 for Unit 2. During those overlapping periods there was an extremely high level of activity to support issuance of the low power license for Unit 2 and to resolve chronic problems with the Unit 2 main steam isolation valves (MSIVs). Although the majority of licensing submittals on Unit 1 during that period were clear and of high quality, a declining trend over the previous period was noted. The declining trend was attributed to the strain on management from the pressing demands for completion of construction of Unit 2. The last SALP on Unit 2 also noted the heavy activity to support Unit 2 licensing and discussed concerns relating to poor planning, a reluctance to provide realistic schedules, and poor coordination among Licensing, Engineering, and site personnel.

Coincident with the issuance of the Unit 2 low power license on October 31, 1986, the Licensing staffs were combined for Units 1 and 2. Thus, Licensing staff experience on operating plant issues was available for Unit 2 activiites.

On occasion during this period, the licensee has exhibited a lack of appreciation for licensing requirements or a reluctance to make independent, conservative decisions with regard to regulatory compliance. Examples of these issues are listed below:

- Deviating from the requirements of the June 24, 1983, order concerning the scram discharge volume (SDV) without obtaining prior NRC approval. (Unit 1)

- Failure to comply with Technical Specifications (TS) concerning the Average Power Range Monitor (APRM) flow biased high flux scram and rod block clamps without NRC intervention. (Unit 1)

- Seeking NRC guidance on which licensee generated analysis to use for the reactor building (RB) ambient service water differential temperature. (Unit 2)

- Failing to respond to NRC Bulletin 86-03 within the required time. (Unit 2)

- Failing to meet the 10 CFR 21 reporting requirements concerning the standby gas treatment (SBGT) system flow switch design deficiency. (Unit 2)

- Failing to apply for an exemption to 10 CFR 50.44 (containment inerting) because of the licensee's interpretation that a special test exception in the TS would take precedence over the regulation. (Unit 2)

While some of these issues have limited safety significance, additional corporate management attention is necessary to ensure aggressive, conservative compliance with regulatory requirements, without waiting for NRC guidance.

During the last assessment period, a concern was noted for Unit 2 with regards to late submittals. While the frequency of late submittals has declined with the licensing of Unit 2, some planning problems have persisted as evidenced by the following:

- February 4, 1988 TS amendment request to redefine Hot Shutdown. (Unit 1)

- January 29, 1988 TS amendment request for the ISI/IST Programs. (Unit 1)

- January 21, 1988 TS amendment to delete the main steam isolation valve bypass valve from the isolation valve list. (Unit 1)

- July 22, 1987 emergency TS change regarding the service water inlet temperature. (Unit 2)

While some of the planning problems relating to the Unit 1 refueling outage may have been caused, in part, by having to enter the outage early, the majority of late submittals appear to be caused by inadequate communications between the Licensing and Operations organizations. Additional corporate management attention is needed to ensure Licensing is aware of amendments and reliefs needed to support restart and continued plant operation. Attention is also needed to ensure that requests are submitted to the NRC in sufficient time to meet public notice requirements and allow for adequate technical review.

Major technical issues during this period for Unit 1 have included: the review of the Inservice Inspection (ISI) and Inservice Testing (IST) Programs; changes to the Radiological TS; the adequacy of the scram discharge volume design modifications; ASME Code relief for the repair of the reactor building heat exchanger and a TS amendment request in support of Reload 11. For Unit 2, the major technical issues during this period have included: MSIV replacement; qualification of non-1E electrical devices; the fire protection program; changes to the service water TS; the downcomer design analysis; the IST program review; the use of Westinghouse fuel; the RB ambient service water differential temperature; and followup to the January 20, 1988 vessel overfill event. With the exception of the issues previously noted, the licensee's technical approach to, and resolutions for, these issues have been generally sound and conservative. For example, as a result of the follow-up review on the January 20 overfill event at Unit 2, the NRC discovered that ASME Code Class 1 analysis had been inappropriately applied to ANSI B31.1 piping in the break exclusion zone. The licensee took timely and effective action to reevaluate the break exclusion zone in the main steamline to respond to NRC concerns, and also extended its reanalysis beyond regulatory requirements to cover other break exclusion zone piping that had been inappropriately analyzed. Additional examples of sound and conservative approaches were: the licensee's submittals in support of deletion of the fire protection sections from the Unit 2 Technical Specifications; and the licensee's submittal on the revisions to the Fire Protection Quality Assurance Program. Both of these submittals were also clear and comprehensive.

Overall, the licensee has generally demonstrated a high degree of cooperation with the NRC while pursuing resolution of concerns in the licensing area. This was evidenced during the Unit 1 and 2 meetings on the IST Program in September and December, 1987, respectively, and during

the review of the containment venting procedures on February 10, 1988. During those meetings, the licensee's staff was professional and responsive, which contributed to the completion of the agenda in a timely manner. One notable exception was the failure of the licensee to discuss the significance of the May 18, 1987 letter on non-1E devices in Class 1E systems with the new Project Manager when it was submitted. Failure to emphasize the significance of this issue during the high activity period immediately before Unit 2 full power licensing, ultimately led to postponing the Commission Briefing. Subsequent to the issuance of the full power license, the licensee has endeavored to keep the NRC advised of developments on this issue.

During the assessment period, there have been a large number of Emergency Notification System (ENS) reports and Licensee Event Reports (LERs) regarding operational and design-related events, particularly on Unit 2. While it is not unusual for plants in the Startup Testing phase to have a higher than average number of event reports, many of these events have been within the licensee's control (i.e., personnel error). Many of the ENS reports were subsequently determined to not be LER reportable; however, the licensee is encouraged to continue their conservative reporting approach.

The reports for Units 1 and 2 have generally been complete and timely. An exception was LER 87-058 concerning the October 1, 1987 scram on high neutron flux. The LER neglected to report that water level had risen to the main steamlines and that some water entered the lines. The apparent lack of sensitivity to a problem (exhibited by the licensee's failure to recognize this aspect of the event as significant) may have contributed to the failure to prevent vessel overfill on January 20, 1988. In addition, the report made to the NRC's Operations Center on the January 20 event neglected to include information on the vessel overfill.

On October 8, 1987, the licensee committed to establish a tracking system for commitments to the NRC and to have a Licensing representative on site to record commitments and ensure they are tracked. While these actions have resulted in fewer missed commitments, the licensee has established a number of overlapping tracking systems with different individuals controlling them. The result is that several licensee representatives have contacted the NRC to request the same information on issues that are tracked on more than one system.

In summary, while the technical approach to, and resolutions for, issues have generally been sound and conservative, the licensee has on occasion, demonstrated a lack of understanding of regulatory requirements and a reluctance to make independent, conservative decisions on issues regarding regulatory compliance. The licensee's cooperativeness has facilitated the timely completion of onsite meetings on licensing issues during this period. However, late submittals, were again noted particularly with respect to the Unit 1 outage at the end of the assessment period.

the review of the containment venting procedures on February 10, 1988. During those meetings, the licensee's staff was professional and responsive, which contributed to the completion of the agenda in a timely manner. However, the licensee needs to ensure that the NRC staff is alerted to items that require immediate attention. On May 18, 1987 the licensee submitted a failure modes and effects analysis for non-1E devices in 1E systems. While the NRC recognizes the licensee's initiative concerning the self-identification of this issue, the licensee should have discussed the significance of the issue with the new Project Manager when it was submitted. Failure to emphasize the significance of the issue during the high activity period immediately before Unit 2 full power licensing, delayed the identification of this issue as an item that needed to be resolved before full power licensing. This late identification led to a two week postponement in the issuance of the full power license. Subsequent to the issuance of the full power license, the licensee has endeavored to keep the NRC advised of developments on this issue.

During the assessment period, there have been a large number of Emergency Notification System (ENS) reports and Licensee Event Reports (LERs) regarding operational and design-related events, particularly on Unit 2. While it is not unusual for plants in the Startup Testing phase to have a higher than average number of event reports, many of these events have been within the licensee's control (i.e., personnel error). Many of the ENS reports were subsequently determined to not be LER reportable; however, the licensee is encouraged to continue their conservative reporting approach.

The reports for Units 1 and 2 have generally been complete and timely. An exception was LER 87-058 concerning the October 1, 1987 scram on high neutron flux. The LER neglected to report that water level had risen to the main steamlines and that some water entered the lines. The apparent lack of sensitivity to a problem (exhibited by the licensee's failure to recognize this aspect of the event as significant) may have contributed to the failure to prevent vessel overfill on January 20, 1988. In addition, the report made to the NRC's Operations Center on the January 20 event neglected to include information on the vessel overfill.

On October 8, 1987, the licensee committed to establish a tracking system for commitments to the NRC and to have a Licensing representative on site to record commitments and ensure they are tracked. While these actions have resulted in fewer missed commitments, the licensee has established a number of overlapping tracking systems with different individuals controlling them. The result is that several licensee representatives have contacted the NRC to request the same information on issues that are tracked on more than one system.

In summary, while the technical approach to, and resolutions for, issues have generally been sound and conservative, the licensee has on occasion, demonstrated a lack of understanding of regulatory requirements and a reluctance to make independent, conservative [illegible] on issues regarding regulatory compliance. The licensee's cooperativeness has facilitated the timely completion of onsite meetings on licensing issues during this period. However, late submittals, were again noted particularly with respect to the Unit 1 outage at the end of the assessment period.

2. Conclusions:

Rating: 2 Declining

3. Board Recommendation:

NRC: None

Licensee: Additional management attention is needed to improve the licensee's sensitivity to issues involving regulatory compliance including the timeliness of both follow-up actions on potential safety issues, submittals on amendments and reliefs required to support plant operations.

I. Training and Qualification Effectiveness:

1. Analysis:

During this assessment period training and qualification effectiveness was again considered a separate functional area, although it continues to be an evaluation criterion for each functional area. This area is used to provide a synopsis of the effectiveness of the training and qualification programs for the Operations Department personnel and other station technical personnel.

This functional area was evaluated for the first time as a separate category in the previous assessment period. Both Unit 1 and Unit 2 were rated as Category 2 in this area, with the following weaknesses observed: lack of indepth training of licensed operators in the operation of the Unit 1 rod worth minimizer; marginal performance by operators at Unit 2 in the areas of procedures and Technical Specifications familiarity; and, lack of training on station administrative procedures.

Observed strengths from the previous period were: development of a non-licensed operator training program; use of "hands-on" training laboratories; strong commitment to licensed operator training; and, good use of the site specific simulators.

During this period, initial Reactor Operator (RO) and Senior Reactor Operator (SRO) license examinations were given for both units. A total of nine SRO candidates were examined. Of the nine candidates, six passed the first time and three individuals from Unit 1 subsequently passed the retake examination. Three RO examinations were given and all candidates passed. Overall performance by candidates on license examinations has been consistent with previous assessment periods. The quality and effectiveness of the operator training program was adequate; however, previously identified weaknesses in the use of procedures has not been fully corrected.

Requalification examinations were given at Unit 2 to four SROs and four ROs. Three of the ROs and two of the SROs passed. Weaknesses in the following areas were observed during the requalification examinations: communications during the simulator examinations; knowledge of APRM calibration and new fuel inspection processes; and, knowledge of what type of fire extinguisher to use for various fire classifications. A strength noted during the examinations was the familiarity with plant equipment locations.

Inspections conducted to evaluate the effectiveness of the operator requalification program at Unit 1 identified that the program was revised during this assessment period to reflect the current 10 CFR 55 requirements for continued training. In addition, some action was taken to correct previously identified weaknesses. Strengths in the requalification program were noted in the use of the site specific simulator, and improved quality of training lectures and lesson plans. A weakness previously identified in the area of requalification training documentation was found not to have improved this assessment period. NRC review of this concern identified that documentation was deficient in the areas of required reading, lecture attendance and remediation.

The results of licensed operator interviews indicated that the Unit 1 operators have the overall opinion that participation in the requalification program is not effective in training the operator to perform job related activities. Operators indicated that the program is unnecessary at Unit 1 due to their extensive operating experience and that the requalification program was designed solely to meet the requirements of INPO and the NRC.

Training Department efforts to improve previously identified weaknesses in training documentation have been ineffective. Operator attitudes toward requalification training indicate that the station management is neither responsive to operator training needs nor supportive of the requalification program.

One problem identified during this assessment period at Unit 1 which may require additional operator training involved a Limiting Safety System Setting (LSSS) violation. Although the LSSS violation was the direct result of a reactor analyst error, it appears that there was no licensed operator oversight of this activity. This may indicate a lack of familiarity of licensed operators with the plant process computer edits for thermal limits. An event last assessment period involving operator lack of familiarity with the rod worth minimizer was addressed with additional operator training and no similar problems were encountered during this assessment.

The adequacy of the non-licensed operator training program has not been directly evaluated in this period. The Unit 2 reactor scram caused by the isolation of instrument air by a non-licensed operator appears to be

an isolated event. However, an obvious deficiency was noted in this operator's method for checking valve positions and may indicate a need for improving the non-licensed operator classroom and on-the-job training.

During this assessment period only one reactor scram was attributed to a station employee's lack of knowledge or training deficiency (October 1, 1987 Unit 2 reactor scram). Several engineered safety feature system automatic actuations occurred at Unit 2 because of either operator or technician lack of familiarity with the systems; however, this was not considered unusual for a plant going through the Power Ascension Testing Program.

A cursory review of Instrumentation and Controls technician training was conducted this assessment period and it was observed to be reasonably well coordinated by the Training Department and work center supervisory oversight was evident. As result of a Unit 2 Self Appraisal Team recommendation, all station departments have implemented their own Lessons Learned Book. The Lessons Learned Book is designed to keep station workers aware of recent problems encountered on site and in the industry to help prevent recurrence. As noted in the Radiological Controls section, radiation protection technicians have not kept abreast of current required reading. Additional supervisory oversight is warranted in this area.

In summary, concerns in the areas of requalification training documentation and operator attitude toward the requalification program need to be reviewed and additional station and corporate management involvement is needed to ensure licensee operator training and requalification training programs are effectively implemented and known program deficiencies are appropriately resolved.

2. Conclusion:

Rating: 2

3. Board Recommendations:

NRC: None

Licensee:
- Audit Requalification Training Program and revise as necessary.
- Examine the station employee training needs for performance; incorporate operators' needs and ideas as appropriate.

J. Assurance of Quality

1. Analysis:

During this assessment period, Assurance of Quality is again being considered as a separate functional area. Management involvement and control in assuring quality continues to be one of the evaluation criteria for each functional area. The various aspects of programs to assure quality have been considered and discussed as an integral part of some functional areas and the respective inspection hours are included in those areas. Consequently, this section is a synopsis of the assessments relating to management involvement and control in assuring the quality of work conducted in all areas and for both units. This section provides a brief outline of past NRC concerns in this area and licensee actions to resolve these concerns. Additionally, the effectiveness of working staff, first line supervisors, management, QA/QC and the independent on site and off site review organizations (SORC and SRAB) in assuring quality is assessed.

During the previous assessment period, this functional area was rated Category 3 for Unit 1 and Category 2 for Unit 2. The numerous weaknesses previously identified included: poor root cause evaluations and overemphasis on procedural revisions to correct problems; inadequate material controls; QA Department overemphasis on post-activity documentation review vice in-process reviews (Unit 1); lack of self-critical analysis and management involvement in problem identification and resolution; poor inter-departmental communications; Operations Department (Unit 2) ill-prepared for power operations; and inappropriate Technical Specification interpretations.

During this assessment period, the licensee made some improvements in their problem identification and resolution processes. Evidence of this was observed in the Licensee Event Reports and in the proceduralizing of the licensee's root cause analysis procedure which was in use much of this assessment period. The root cause procedure typically required a single person to develop the line of inquiry and conduct an investigation using Kempner Tregoe (KT) as a tool for analysis. The KT analysis was then reviewed by the SORC. Because the KT analysis was generally developed by one individual, it appeared that the multidisciplinary SORC review would be more effective if used from the outset.

Licensee performance has been inconsistent, in that examples persisted where management was either unable to identify the underlying or programmatic causes or did not effectively pursue them such as: reactor building ventilation isolations and subsequent standby gas treatment (SBGT) system automatic initiations; reactor water cleanup pump bearing failures; Rosemount transmitter sensitivity problems; emergency diesel generator lube oil pressure switch problems (Unit 1); liquid poison pump breaker problems (Unit 1); repeat fire protection program violations involving personnel error; Inservice Inspection (ISI) program implementation concerns; and

persistent housekeeping problems. In contrast, licensee actions to address the spurious redundant reactivity control system actuations, the Electro-Hydraulic Control system pipe break, the condensate storage tank rupture, and the feedwater system transient at Unit 1 were examples of timely and comprehensive corrective actions. In general, licensee identification and resolution of site problems has shown improvement, but further station management attention is warranted to ensure that the improvement continues.

Examples of material control problems continued to surface such as, the control of commercial grade items in safety related applications which has been a problem area. In May 1987, a Quality Assurance (QA) audit identified the lack of proper commercial grade dedication for General Electric Company (GE) supplied commercial grade items. The licensee's Materials Management Organization purportedly placed all these items on hold pending appropriate dedications. In January 1988, the site QA Surveillance group identified that a few GE commercial grade items had been improperly issued without dedication and a QA Stop Work Order was initiated. Subsequently on February 2, 1988, a second Stop Work Order was issued by QA on all non-GE commercial grade items pending review of these items' commercial grade dedications and item identification and segregation in the warehouses. Although QA involvement to assure proper resolution of this materials control concern was decisive and thorough, more positive action to prevent potential safety concerns should have been taken by station and Materials Control management in May 1987 to preclude inadvertent issue of unauthorized equipment.

In the previous assessment period, the site QA organization at Unit 1 was identified as being more oriented towards post-activity documentation reviews than in-the-field work observations. This was in sharp contrast to the Unit 2 QA efforts which were focused on field observations and in-process work activities. During this assessment period the station QA organization has been restructured under the direction of a new Manager of Nuclear QA Operations. In addition, the station QA Surveillance Program was changed to ensure more in-the-field surveillance rather than after-the-fact paper reviews at both units. The surveillance program also includes review of startup test activities with 24 hour coverage and detailed surveillance checklists for certain pre-selected tests. The QA Surveillance organization has changed their method of selecting areas to be observed by utilizing random selection of work activities and the Probability Risk Assessment (PRA) analysis. These changes are indicative of QA management willingness to ensure that more in-the-field activities are observed in order to achieve higher quality work. The use of the PRA also exemplifies management's aggressiveness in identifying areas of higher safety significance and to focus more attention on these areas.

QA involvement in the MSIV replacement at Unit 2 was good. Short term station QA initiatives taken in October 1987 to correct the Unit 1 ISI programmatic deficiencies were also good. However, QA Audit findings in July 1987 did not receive adequate followup by either QA or station and corporate management, in order to determine the potential safety system impact.

Management continues to struggle with the ability to be critical of their own performance, although some examples of improvement have been observed. Unit supervisor meetings have been scheduled with the respective Unit Superintendents to improve information flow and direct oversight of unit activities. However, these meetings do not appear to be effective in improving radiological controls and housekeeping practices at Unit 1.

Housekeeping at Unit 1 continued to be a problem area; marginal improvement towards the end of the assessment period was observed, but only after unsatisfactory observations were presented to station management by the NRC. Routine cleaning activities have been observed and specific problem areas identified by the NRC are usually addressed. Station management does not aggressively stress good housekeeping practices to station workers but rather leaves that responsibility to the Buildings and Grounds Maintenance crew.

The failure of the licensee to identify problems in the Unit 1 ISI program, in November 1986 with the RBCLC heat exchanger concern, again in July 1987 after a QA audit of ISI, in October 1987 with the discovery of unresolved ISI examination results, and in December 1987 with the discovery of missed vessel head stud bushing examinations, indicate that station and corporate management did not critically examine the causes for these problems nor did they recognize the potential programmatic concerns. The four scram valve diaphragm failures at Unit 1, the offgas system problems at Unit 2, the RWCU pump spare parts availability at Unit 2, and the numerous hot particle problems at Unit 1 are all examples of where management has either been slow to recognize the potential problem or slow to take action to correct the situation.

The effort expended by the licensee's Unit 2 Self-Appraisal Team (SAT) proved beneficial but has not been fully implemented by all site supervisors and managers. Maintenance supervision has been observed in the field providing direct oversight and interaction with the mechanics, however Radiation Protection supervision monitoring of ongoing work during the Unit 1 outage has been poor. Specifically, during drywell work the lack of supervisory oversight has led to unnecessary personnel exposures and the tolerance of sloppy work habits.

The September 2, 1987 event at Unit 2, involving the inoperability of SBGT train A because of a missed surveillance on the charcoal filter media, demonstrates insufficient corporate and station management involvement. Another example of inadequate management involvement, which also resulted in escalated enforcement, was the Unit 1 Inservice Inspection (ISI) Program implementation violations identified in October 1987. Although the ISI Program violations were initially determined to be of low safety significance, the principal concerns were for the number of

deficiencies, the time these problems existed and the number of missed opportunities for station and corporate management to take action to correct these deficiencies. On the other hand, development of the Engineering Task Force management approach and the use of SAT, which was encouraged by NRC management, were beneficial in identifying and resolving station problems and were good licensee management initiatives.

Communications and coordination between various groups on site remains a historical licensee weakness. Some examples of good coordination were evident, such as the replacement of the MSIVs at Unit 2 and the development and implementation of the Unit 1 Work Control Center. However, early in the assessment period many of the attendees at the Unit 2 planning meetings were ill-prepared and sometimes uncooperative. Station management efforts to improve this situation were slow and corporate management presence at these meetings was infrequently observed. Similarly, licensee SORC meeting discussions appeared generally strained. Although safety issues were adequately reviewed and appropriately resolved, the discussions were frequently unstructured and items for SORC review were often inefficiently presented. Efforts by the SORC chairmen to direct the discussions and reviews appeared to often result in SORC members and attendees being inhibited rather than encouraged to freely discuss observations and concerns. The quality of presentations made to the SORC should be better planned and more efficiently presented to ensure a better inter-disciplinary safety review.

SORC involvement in the resolution of Unit 2 Power Ascension Testing major test exceptions and related plant problems has been significantly improved. The SORC members have consistently demonstrated a clear understanding of the technical and safety aspects of the testing issues and have routinely taken actions that are conservative with respect to safety. Particularly noteworthy were the actions taken to address the feedwater temperature stratification problem, spurious actuations of the redundant reactivity control system and the reactor scram with subsequent vessel overfill event.

The Unit 2 Operations Department has demonstrated general improvement. The operating crews have conducted the Power Ascension Test Program well, with few significant personnel errors. When operator related problems have been encountered, supervisory response has been prompt and thorough review of the human factors elements has been performed to ensure actions to prevent recurrence are proper and the lessons learned are quickly communicated to all operators. The assignment of new management staff was observed to improve communications and responsiveness both within and outside the Operations Department.

The deficiencies noted towards the end of the assessment period in the Unit 1 licensed operator requalification program implementation indicate that additional management attention is needed in this area to improve the overall quality of the requalification program and operator receptiveness to the training.

Licensee approach to interpretation of Technical Specifications (TS) was generally improved. A TS Interpretation Book was generated for Unit 2 licensed operator use and appears to have appropriate controls for ensuring adequate review and approval of the interpretations prior to their application. However, an example at Unit 1 involving a TS interpretation for isolating a recirculation loop indicates that the lessons learned at Unit 2, regarding appropriate research and review of TSs and when in doubt erroring in the conservative direction, were not carried over to Unit 1 staff.

Activities of the offsite review committee, the Safety Review and Audit Board (SRAB), do not appear to be exceptionally effective in overseeing station operations. For example, the ISI audit conducted in July 1987 which identified programmatic weaknesses did not receive any obvious immediate followup. Also, a SRAB audit of Requalification Training at Unit 1 was considered ineffective as demonstrated by recent NRC inspections in this area. Although observations of SRAB functions have been limited this assessment period, the SRAB's impact on day to day site operations and overall site performance was not readily apparent.

In summary, performance in this area is inconsistent. NMPC has made minimum overall improvement in this area since the last SALP. The improvements made in problem identification and resolution, effectiveness of Quality Assurance organization, Unit 2 operations and TS interpretations were balanced by the surfacing of station and corporate management oversight and coordination problems such as the ISI Program, material controls, requalification training, SBGT system missed surveillance and persistent radiological controls and housekeeping problems. The lack of station teamwork and good communications is still evident and indicative of poor station and corporate leadership. Efforts to improve, to date, have been too slow.

2. Conclusion:

Rating: 3

3. Board Recommendations:

NRC: None

Licensee: Complete the reorganization and more clearly define staff responsibilities and accountability.

V. SUPPORTING DATA AND SUMMARIES

A. Investigations and Allegation Summary

An Office of Investigation review of a 1985 allegation, on improper installation of nuclear instrumentation cables continued through this

assessment period. An Enforcement Conference was conducted on March 18, 1988.

During this assessment period, a total of seven allegations were received and reviewed by the NRC. Six were found to be valid concerns. One allegation is currently under review.

B. Escalated Enforcement Actions

An Enforcement Conference was held on February 19, 1987, to discuss numerous violations identified during the previous assessment period involving concerns brought to the NRC's attention by a NMPC station employee. A Notice of Violation was issued on April 29, 1987, detailing five instances of violation, citing a aggregate Severity Level III and cumulative $50000 dollar Civil Penalty.

An Enforcement Conference was held on July 7, 1987, subsequent to an inspection of a radioactive materials shipment from Unit 1 to the Brunswick Nuclear Station. A Notice of Violation was issued on August 13, 1987, citing a Severity Level III violation of 49 CFR Parts 170-189, and assessing a $2,500 dollar Civil Penalty.

An Enforcement Conference was held on October 8, 1987, to discuss a Technical Specification surveillance testing violation involving the sampling of charcoal filters in the Standby Gas Treatment system.

An Enforcement Conference was held on January 7, 1988 to discuss a resident inspector report which detailed numerous violations of the licensee's Inservice Inspection Program at Unit 1. After the end of the assessment period on March 14, 1988, a Notice of Violation was issued for these violations. The three violations have been categorized in the aggregate as a Severity Level III with a cumulative $100,000 dollar Civil Penalty.

C. Management Conferences

The management meetings for the previous SALP periods were held on March 26 and June 12, 1987, for Unit 1 and Unit 2 respectively.

On September 21, 1987, the licensee presented their Self-Appraisal Team (SAT) findings to Region I and Headquarters staff at the licensee's Training Center.

D. Confirmatory Action Letters (CAL)

One CAL was issued this period to Unit 2 after the January 20, 1988, loss of feedwater and vessel overfill event. This CAL confirmed that the plant would remain shutdown until Region I management had time to review the events and licensee corrective action. The shutdown requirement was lifted on February 1, 1988.

E. Licensing Activities

1. UNIT 1

a. LICENSEE MEETINGS (AT NRC)

-- Licensing Issues	4/24/87
-- Discussion of New Seismic Criteria	6/26/87
-- Licensing Issues	11/17/87

b. SITE VISITS/MEETINGS

-- Management Meeting and Plant Tour	5/13-14/87
-- Discussion of Inservice Testing Program for Pumps and Valves	9/9-10/87
-- Review of Containment Venting Procedures	2/10/88

c. COMMISSION MEETINGS

-- None

d. RELIEFS AND SCHEDULAR EXEMPTIONS GRANTED

-- Code Relief for Heat Exchanger Repair	3/20/87
-- CRD Stub Tubes	3/25/87
-- Relief from 60 Day Reporting Requirement for GL 87-02	5/12/87

e. EXEMPTIONS GRANTED

-- None

f. LICENSE AMENDMENTS ISSUED

AMENDMENT	SUBJECT	DATE
89	Organization Technical Specification Changes	11/17/86
90	Technical Specification For Engineering Expertise on Shift	12/29/86
91	Control Room Air Treatment System	2/10/87
92	Technical Specification On Power/Flow Rate	3/24/87
93	Organization Technical Specification Changes	8/27/87

94	Radiological Environmental Technical Specification Changes	2/8/88

2. UNIT 2

a. LICENSEE MEETINGS

-- Licensing Issues	4/24/87
-- Non 1E Devices	6/10/87
-- Operational Problems from Hot Weather	7/20/87
-- Drawdown Time	8/18/87
-- Licensing Issues	11/17/87
-- Downcomers	12/07/87
-- Westinghouse Fuel	1/20/88

b. SITE VISITS/MEETINGS

-- Management Meeting and Plant Tour	5/13-14/87
-- Non 1E Devices	6/15-16/87
-- Inservice Testing	12/3-4/87

c. COMMISSION MEETINGS

-- Full Power Commission Briefing	7/01/87

d. RELIEFS OR EXEMPTIONS GRANTED

-- Schedular Exemption to GDC 50	7/2/87

e. AMENDMENTS

-- Delete MSIV License Amendment (AM. 1 TO NPF-54)	5/11/87
-- Revise RPS Setpoints and Change to WYE-Pattern Globe Valves (AM. 2 TO NPF-54)	5/15/87
-- Emergency Technical Specification Change on Service Water (AM. 1 TO NPF-69)	7/31/87
-- RCIC Setpoints (AM. 2 to NPF-69)	3/24/88

f. OTHER LICENSING ACTIONS

-- Full Power License	7/2/87
-- Full Power Technical Specifications	7/2/87
-- SSER 6	7/2/87

TABLE 1

INSPECTION REPORT ACTIVITIES

Unit 1	Unit 2	Inspector	Hours (Unit1/Unit2)	Areas Inspected
86-21 10/01/86 - 11/16/86		Resident	28/0	A
(86-22 and 86-23 were outside the assessment period)				
86-24 11/03/86 - 11/07/86		Specialist	68/0	Maintenance Program Review
86-25 11/17/86 - 11/21/86		Specialist	19/0	B
86-26 11/17/86 - 01/04/87		Resident	99/0	A
86-27 12/01/86 - 12/05/86		Specialist	27/0	B
87-01 01/04/87 -	87-02 03/01/87	Resident	226/175	A
87-02 01/12/87 - 01/16/87		Specialist	19/0	B
	(87-03 and 87-04 were outside the assessment period)			
	87-05 02/02/87 - 02/05/87	Specialist	0/26	Routine inspection to review MSIV control and electrical modifications
	87-06 02/10/87 - 02/13/87	Specialist	0/48	C
	87-07 02/09/87 - 02/13/87	Specialist	0/37	Routine safety inspection of electrical and mechanical surveillance and maintenance

(Areas Inspected Codes are described at the end of this Table.)

SEE AMENDED PAGE FOLLOWING

Table 1 (Cont'd)

INSPECTION REPORT ACTIVITIES

Unit 1	Unit 2	Inspector	Hours (Unit1/Unit2)	Areas Inspected
87-03 03/02/87 -	87-09 04/19/87	Resident	141/279	A
87-04 04/06/87 -	87-10 04/10/87	Specialist	17/17	D
87-05 04/06/87 - 04/09/87		Specialist	N/A	Operator License Exam
87-06 04/20/87 - 04/24/87		Specialist	32/0	B
87-07 04/20/87 -	87-08 06/07/87	Resident	160/315	A
87-08 05/26/87 - 05/27/87		Specialist	15/0	Special safety inspection of Rad material shipping
	87-11 03/23/87 - 03/27/87	Specialist	0/37	Routine inspection to review MSIV replacement
	87-12 04/06/87 - 04/10/87	Specialist	0/40	Routine safety inspection of electrical and and pneumatic modification due to MSIV
	87-13 04/20/87 - 04/21/87	Specialist	0/19	Special safety inspection of fire protection program
	87-14 04/13/87 - 04/17/87	Specialist	0/37	Routine safety inspection to review MSIV charge out
	87-15 05/11/87 - 05/15/87	Specialist	0/34	C
	87-16 06/01/87 - 06/12/87	Specialist Team	0/1532	Special Operational Readiness Inspection

Table 1 (Cont'd)

INSPECTION REPORT ACTIVITIES

Unit 1	Unit 2	Inspector	Hours (Unit1/Unit2)	Areas Inspected
87-03 03/02/87 -	87-09 04/19/87	Resident	141/279	A
87-04 04/06/87 -	87-10 04/10/87	Specialist	17/17	D
87-05 04/06/87 - 04/09/87		Specialist	N/A	Operator License Exam
87-06 04/20/87 - 04/24/87		Specialist	32/0	B
87-07 04/20/87 -	87-08 06/07/87	Resident	160/315	A
87-08 05/26/87 - 05/27/87		Specialist	15/0	Special safety inspection of Rad material shipping
	87-11 03/23/87 - 03/27/87	Specialist	0/37	Routine inspection to review MSIV replacement
	87-12 04/06/87 - 04/10/87	Specialist	0/40	Routine safety inspection of electrical and and pneumatic modification due to MSIV
	87-13 04/20/87 - 04/21/87	Specialist	0/19	Special safety inspection of fire protection program
	87-14 04/13/87 - 04/17/87	Specialist	0/37	Routine safety inspection to review MSIV charge out
	87-15 05/11/87 - 05/15/87	Specialist	0/34	C
	87-16 06/01/87 - 06/12/87	Specialist Team	0/632	Special Operational Readiness Inspection

Table 1 (Cont'd)

INSPECTION REPORT ACTIVITIES

Unit 1	Unit 2	Inspector	Hours (Unit1/Unit2)	Areas Inspected
	87-17 05/19/87 - 05/29/87	Specialist	0/73	C
	87-18 07/07/87 - 07/09/87	Specialist	N/A	Operator License Exam
87-09 06/10/87 -	87-19 06/11/87	Specialist	17/13	D
87-10 06/08/87 -	87-20 07/19/87	Resident	194/276	A
87-11 06/29/87 -	87-25 07/10/87	Specialist	33/37	Nondestructive testing
	87-21 06/08/87 - 06/19/87	Specialist	0/69	C
87-12 06/22/87 -	87-22 07/01/87	Specialist	12/139	B
	87-23 06/22/87 - 06/30/87	Specialist	0/52	C
87-13 07/20/87 -	87-29 08/30/87	Resident	134/247	A
87-14 07/27/87 -	87-30 07/31/87	Specialist	18/18	D
87-15 08/03/87 -	87-24 08/07/87	Specialist	35/39	B
87-16 08/03/87 - 09/11/87		Specialist	N/A	Operator License Exam
87-17 08/24/87 -	87-34 08/27/87	Specialist	30/30	B

Table 1 (Cont'd)

INSPECTION REPORT ACTIVITIES

Unit 1	Unit 2	Inspector	Hours (Unit1/Unit2)	Areas Inspected
	87-26 07/06/87 - 07/10/87	Specialist	0/37	C
	87-27 08/03/87 - 08/12/87	Specialist	0/60	C
	87-28 07/20/87 - 07/24/87	Specialist	0/34	C
87-18 08/31/87 -	87-37 10/04/87	Resident	86/146	A
87-19 08/25/87 -	87-31 08/26/87	Specialist	91/91	EP Drill Observation
87-20 09/14/87 -	87-36 09/18/87	Specialist	20/16	B
	87-32 09/01/87 - 09/08/87	Resident	0/54	Special Inspection of SBGT violation
	87-33 08/24/87 - 08/28/87	Specialist	0/34	C
	87-35 09/21/87 - 09/23/87	Specialist	0/51	C
	87-38 10/12/87 - 10/15/87	Specialist	0/23	C
87-21 10/05/87 -	87-39 10/30/87	Resident	136/195	A
87-22 10/19/87 - 10/23/87		Specialist	82/0	Design changes and Maintenance

Table 1 (Cont'd)

INSPECTION REPORT ACTIVITIES

Unit 1	Unit 2	Inspector	Hours (Unit1/Unit2)	Areas Inspected
	87-40 10/19/87 - 10/22/87	Specialist	0/56	D
87-23 11/03/87 - 11/06/87		Specialist	32/0	Corporate Engineering
	87-41 11/02/87 - 11/06/87	Specialist	0/34	C
87-24 10/31/87 -	87-42 12/10/87	Resident	108/196	A
	87-43 12/14/87 - 10/24/88	Specialist	N/A	Operator License Exam
	87-44	Not Issued		
87-25 12/11/87 -	87-45 02/02/88	Resident	194/209	A
88-01 01/11/87 - 01/15/87		Specialist	94/0	Corporate Engineering
	88-01 01/22/88 - 01/24/88	Augmented Inspection Team	0/150	Vessel overfill event
88-02 01/11/88 - 01/14/88		Specialist Team	88/0	Feedwater Piping Transient
88-03 02/01/88 -	88-02 03/14/88	Resident	68/64	A
	88-03 01/25/88 - 01/29/88	Specialist	1/20	Vessel overfill event
	88-04 02/22/88 - 02/26/88	Specialist	0/34	C

SEE AMENDED PAGE FOLLOWING

Table 1 (Cont'd)

INSPECTION REPORT ACTIVITIES

Unit 1	Unit 2	Inspector	Hours (Unit1/Unit2)	Areas Inspected
88-04 02/15/88 -	88-05 02/14/88	Specialist	35/8	B
88-05 02/22/88- 02/29/88		Specialist	N/A	Operators License Exam
		TOTALS	2359/4101	

A - Routine Safety Inspection by Resident Inspector
B - Routine Inspection of Radiation Controls and Chemistry
C - Routine Inspection of Power Ascension testing, Surveillance testing, and Preoperational test results
D - Routine Physical Security Inspection

Table 1 (Cont'd)

INSPECTION REPORT ACTIVITIES

Unit 1	Unit 2	Inspector	Hours (Unit1/Unit2)	Areas Inspected
88-04 02/15/88 -	88-05 02/14/88	Specialist	35/8	B
88-05 02/22/88- 02/29/88		Specialist	N/A	Operators License Exam

TOTALS 2359/4201

A - Routine Safety Inspection by Resident Inspector
B - Routine Inspection of Radiation Controls and Chemistry
C - Routine Inspection of Power Ascension testing, Surveillance testing, and Preoperational test results
D - Routine Physical Security Inspection

SEE AMENDED PAGE FOLLOWING

TABLE 2

INSPECTION HOURS SUMMARY

FUNCTIONAL AREA	HOURS	% OF TIME
A. Operations	(3207)	(49.7)
1. Unit 1	1147	17.7
2. Unit 2	2060	32.0
B. Rad Protection	614	9.5
C. Maintenance	718	11.1
D. Surveillance	(1054)	(16.3)
1. Unit 1	163	2.5
2. Unit 2	891	13.8
E. Engineering/ Technical Support	418	6.5
F. Security and Safeguards	216	4.1
G. Emergency Preparedness	182	2.8
H. Assurance of Quality	*	
I. Training and Qualification Effectiveness	*	
J. Licensing	**	
Total	6460	100 %

* Hours expended in the areas of assurance of quality and training are included in other functional areas, therfore, no direct inspection hours are given for these areas. Operator licensing activities are not included with direct inspection effort statistics.

** Hours expended in facility licensing activities are not included in direct inspection effort statistics.

TABLE 2

INSPECTION HOURS SUMMARY

FUNCTIONAL AREA	HOURS	% OF TIME
A. Operations	(3307)	(50.4)
1. Unit 1	1147	17.5
2. Unit 2	2160	32.9
B. Rad Protection	625	9.5
C. Maintenance	718	10.9
D. Surveillance	(1054)	(16.1)
1. Unit 1	163	2.5
2. Unit 2	891	13.6
E. Engineering/ Technical Support	418	6.4
F. Security and Safeguards	256	3.9
G. Emergency Preparedness	182	2.8
H. Assurance of Quality	*	
I. Training and Qualification Effectiveness	*	
J. Licensing	**	
Total	6560	100 %

* Hours expended in the areas of assurance of quality and training are included in other functional areas, therfore, no direct inspection hours are given for these areas. Operator licensing activities are not included with direct inspection effort statistics.

** Hours expended in facility licensing activities are not included in direct inspection effort statistics.

TABLE 3

LICENSEE REPORTABLE EVENTS

Cause Determined by SALP Board

An assesment has been conducted to determine the root cause of each event from the perspective of the NRC. The causes fell into the following categories and sub-categories.

Personnel Errors (PE)

1. Lack of Knowledge (LK) - the individual was not properly trained or provided with instructions from supervision.

2. Inattention to Detail (ID) - the individual failed to pay proper attention to a task and was careless.

3. Poor Judgement (PJ) - the individual failed to make the correct assessment with the proper amount of training and attention to facts.

Equipment Malfunction/Failure (EM/EF)

1. Random (R) - isolated component problem not of generic concern.

2. Design Deficiency (DD) - poor design was the cause of the malfunction/failure.

3. Construction Deficiency (CD) - improper installation during construction/modification caused or could have caused the malfunction/failure.

4. Maintenance Deficiency (MD) - improper preventive or corrective maintenance.

Procedural Error (PROE)

The procedure failed to provide adequate instruction, was poorly worded or was not properly reviewed for use.

Ineffective Corrective Action (ICA)

Action was not taken by management or the action taken on a previously identified item was not timely or did not correct the root cause and allowed this occurence.

Causes As Determined By the Licensee

The licensee is required to include cause codes in the write-ups for events. These codes are only required when equipment malfunction or failure is determined to be the cause of the occurence. The following codes are used:

A - Personnel Error
B - Design, Manufacturing, Construction or Installation
C - External Cause
D - Defective Procedures
E - Component Failure
X - Other

SALP TABLE 3.1.

Unit 1 Summary of Causes Determined by SALP Board by Functional Areas

CAUSE	OPS	RAD	MAINT	SURV	ENG/TS	SEC	TOTAL
PE/LK			1				1
PE/ID	4	1	1	6	5	1	18
PE/PJ	1				1		2
EM/F/R		1	2				3
EM/F/DD		1	2		4		7
EM/F/MD			3				3
PROE				1			1
ICA					2		2
TOTAL	5	3	9	7	12	1	37*

Summary of Causes of Equipment Malfunctions/Failure Determined by Licensee

AREA	A	B	C	D	E	X	Total
RAD	1				1	1	3
MAINT	2	2			2		6
ENG/TS		3					3
Totals	3	5			3	1	12

* Three LERS were assigned two separate cause codes.

SALP TABLE 3.1
Unit 1 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
11/21/86	86-33 B	TS Violation: Rx Building Closed Loop Cooling Heat Exchanger not declared inoperable after failing ISI Hydro test.	PE/PJ - Engineering failed to perform a proper evaluation of significance of the RBCLC heat exchanger leak.	ENG/TS
12/06/86	86-34 A	TS Violation: Loss of Stack gas sample flow due to software problem.	EM/DD - Equipment self-monitoring program did not function properly.	RAD
12/10/86	86-35	TS Violation: Secondary Containment integrity due to simultaneous opening of air lock doors.	PE/ID - Security guard improperly responded to an alarm on air lock doors.	SEC
01/09/87	87-01	TS Violation: Failure of the Rx Manual Control System design to meet TS.	PE/ID - APRM rod blocks and flow bias trip functions not clamped at 100% flow. Surveillance test was inadequate.	SURV
01/26/87	87-02 A	Agastat GP Series relay installation deficiency and potential failure.	PE/LK - Relays improperly installed because of lack of sufficient guidance.	MAINT
02/06/87	87-03 E	Secondary Containment Isolation/Auto Start RX Building emergency ventilation: Spurious trip of radiation monitor.	EM/R - detector determined to have a faulty sensor and converter card.	RAD

* Indicates licensee's Cause Code for equipment failures only.

SALP TABLE 3.1

Unit 1 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
02/10/87	87-04	TS Violation: Failure to perform surveillance testing within required interval.	PE/ID - Responsible supervisor did not ensure 3.25 times the the specified interval was adhered to.	SURV
03/13/87	87-05	TS Violation: Failure to perform analysis due to lost stack Composite Particulate Sample.	PE/ID - Stack sample was lost at the testing lab due to apparent carelessness.	RAD
03/24/87	87-06	TS Violation: Failure to perform daily starting air tank pressure readings for the diesel firepump.	PE/ID - Fire Department supervisor improperly revised the surveillance test procedure.	OPS
03/27/87	87-07	TS Violation: Failure to meet requirements for fire rated penetrations.	PE/ID - Site personnel failed to recognize the the proper fire seal requirements for these penetrations.	OPS
			PROE - The surveillance procedure ommitted several penetrations for inspections.	SURV
05/12/87	87-08	TS Violation: Fire -rated barrier containing nonqualified piping.	PE/ID - Numerous fire-rated penetrations inadequate, discovered during comprehensive engineering review.	ENG/TS
06/04/87	87-09	TS Violation: Vibration Instrumentation not in compliance with ASME Section XI.	PE/ID - Personnel improperly implemented the ASME Code requirements.	SURV

SALP TABLE 3.1
Unit 1 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
06/12/87	87-10 X	TS Violation: Stack gas sample pump failure due to deteriorated components.	EM/MD - Sample pump failure due to aging/ wear.	MAINT
07/03/87	87-11	TS Violation: Failure to perform surveillance testing within required interval.	PE/ID - Technician failed to perform surveillance and inadequate supervisory oversight.	SURV
07/24/87	87-12 B	Temporary loss of both Emergency Diesel Generators.	EF/DD - Excessive vibration of EDG caused governor solenoid to fail.	MAINT
			PE/ID - Licensee failed to include vendor maintenance recommendation.	MAINT
08/02/87	87-13 E	Rx Building emergency ventilation initiation caused by relay failure.	EF/R - Timing relay failed due to aging resulting in instrument trip.	MAINT
10/16/87	87-14 A	Rx Scram: HPCI and MSIV closure due to electrical pressure regulator servo-valve malfunction.	EM/MD - Servo-valve malfunctioned because of dirty control oil, preventive maintenance was inadequate.	MAINT
10/17/87	87-15 B	Rx scram, turbine trip and HPCI initiation signals due to spurious trip of neutron monitor caused by noise (while S/D).	EM/DD - Spurious neutron monitoring system spike due to noise.	ENG/TS

SALP TABLE 3.1
Unit 1 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
10/19/87	87-16 B	Rx Scram, Turbine Trip, and HPCI initiation signals due to spurious trip of neutron monitor caused by noise (while S/D).	EM/DD - IRM spike due to noise	ENG/TS
10/20/87	87-17	TS Violation: Incorrect system piping design specification resulted in a portion of the raw water core spray intertie piping receiving hydro test at incorrrect pressure.	PE/ID - Engineering incorrectly classified the piping design specifications in a 1983 modification.	ENG/TS
10/22/87	87-18	TS Violation: Inappropriate procedure deletion.	PE/ID - Special Operating Procedure N1-SOP-5 deleted from Master File without appropriate administrative review.	OPS
10/21/87	87-19	TS Violation: Failure to identify unacceptable fire rated penetrations.	PE/ID - Numerous fire rated penetrations were not identified during an earlier 1984 review conducted by contractors.	ENG/TS
10/27/87	87-20	TS Violation: Missed firewatch patrol.	PE/ID - The firewatch overlooked the required patrol listed on the the Patrol Status Sheet.	OPS

SALP TABLE 3.1
Unit 1 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
10/27/87	87-21	TS Violation: Failure to reduce power below TS limit prior to isolating recirculation loop.	PE/PJ - Licensee failed to take conservative action when in doubt of TS interpretation.	OPS
11/15/87	87-22	TS Violation: Failure to reduce rod block and scram setpoints.	PE/ID - Responsible reactor analyst missed the requirement to take corrective action for MTPF 3.0	SURV
04/22/87	87-23	Rx Building emergency ventilation initiation and and failure to properly report the event per 50.73.	PE/ID - Technician inadvertently grounded a control circuit causing a fuse to blow resulting in the RBEV actuation.	SURV
			PE/ID - Licensee failed to properly track and report the event per 50.73.	ENG/TS
12/07/87	87-24 E	Rx scram on low reactor water level.	EM/MD - Feedwater control valves did not properly respond to level control signal and attempted corrective actions resulted in scram.	MAINT
12/10/87	87-25 B	Rx Scram (while S/D) due to spurious trip of neutron monitor caused by noise.	EM/DD - Spurious instrument (IRM) trips due to noise.	ENG/TS

SALP TABLE 3.1
Unit 1 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
10/30/87	87-26	TS Violation: perform ASME Code examination requirements prior to placing component restraints in service.	PE/ID - Engineering failed to identify Code requirements for a pipe restraint modification.	ENG/TS
12/09/87	87-27	TS Violation: ISI Program deficiencies.	ICA - Management ineffectiveness in implementing and overseeing the ISI Program.	ENG/TS
12/19/87	87-28 E	Manual Rx scram initiated due to feedwater piping vibration.	EF/DD - Feedwater control valve 13A stem to disc separated due to fatique failure.	MAINT ENG/TS
01/15/88	88-01	TS Violations: ISI program deficiencies.	ICA - Management ineffectiveness in implementing and overseeing the ISI program.	ENG/TS

SALP TABLE 3.2.

Unit 2 Summary of Causes Determined by SALP Board by Functional Areas

CAUSE	OPS	RAD	MAINT	SURV	ENG/TS	TOTAL
PE/LK	3		1	4	2	10
PE/ID	30	2	3	10	5	50
PE/PJ	6				2	8
EM/F/R			1	2	2	5
EM/F/DD		1	1		35	37
EM/F/CD					2	2
PROE	5			8	1	14
ICA	3			1	5	9
TOTAL	47	3	6	25	54	135 *

Summary of Causes of Equipment malfunctions/Failure Determined Licensee

AREA	A	B	C	D	E	X	Total
OPS		2				3	5
RAD			1				1
MAINT	1					1	2
ENG/TS						2	2
Totals	1	2	1			6	10

* Multiple cause codes assigned; 85 total LERs.

SALP TABLE 3.2.

Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
02/02/87	87-06 X	Partial Primary Containment Isolation: MSIV closure during surveillance testing.	PROE - Procedure for checking reverse flow check valves did not specify to reset possible isolation signals that could have been generated by the testing.	SURV
02/02/87	87-07 A	Secondary Containment Isolation/Auto Start of SBGT: Low reactor building normal ventilation flow (RBV).	PE/ID - A technician bumped a control relay while working in a normal reactor building ventilation cabinet causing a supply fan trip.	MAINT
02/02/87	87-10	Spurious Rx scram, HPCS start signal, (no initiation) HPCS diesel start: Reactor vessel Level 2 and Level 3 instrument trip.	PE/ID - A technician opened an isolation valve on an isolated detector when he was to check the valve shut.	SURV
			EM/DD - The reactor vessel level detectors are too sensitive to pressure spikes on instrument lines.	ENG/TS
02/07/87	87-11	Spurious Rx scram, turbine and feedwater pump trip signal (no trip) Reactor. vessel Level 3 and Level 8 trip.	EM/DD - The reactor vessel level detectors are too sensitive to pressure spikes on instrument lines. In this case, flexible instrument tubing was bumped.	ENG/TS

* Indicates licensee's Cause Code for equipment failures only.

Note: LERs 87-08 and 87-09 covered in the previous SALP period.

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
02/08/87	87-12	Inadvertant MSIV closure during surveillance testing	PE/ID - Senior Reactor Operators allowed a surveillance test to be conducted on Turbine Stop Valve which caused the closure of the MSIVs.	OPS
			PROE - The surveillance procedure being used did not contain information on resetting the turbine for testing with the turbine output breaker closed for station backfeed.	SURV
02/09/87	87-13 X	Secondary Containment Isolation/ Auto Start of Control Room Emergency Ventilation: Loss of Division 2, 600V load center.	PE/ID - Reactor Operator opened the breaker that was actually supplying power to the bus due to burnt out breaker position lights and an unexplained breaker repositioning.	OPS
			PE/ID - The alternate supply breaker was shut and the normal open by a person unknown.	OPS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
01/29/87	87-14	TS violation: Gaseous Effluent Radiation Monitor System (GEMS) instruments inoperable without proper compensating action taken.	PE/ID - The TS required flowrate meters were declared operable with work requests outstanding on the instruments.	OPS
			PE/ID - The instrument used to calibrate TS required flowrate meters was not properly calibrated, so the instrument was not properly calibrated.	RAD
			PE/ID - Inadequate oversight by chemistry department supervisors.	RAD
			PE/ID - Lack of questioning attitude by SSS.	OPS
02/22/87	87-15	TS violation: missed fire watch.	PE/PJ - Fire watch personnel split up fire patrol work load without fully briefing the other personnel on special instructions given by supervisor.	OPS
02/26/87	87-16	TS violation: inoperable fire wall due to improperly sealed penetration.	PE/PJ - Engineering judged the penetration at first to be operable and then inoperable.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
02/24/87	87-17	Partial Primary Containment Isolation a : Auto Start of SBGT: Loss of power to RPS Division 2 loads simulated a LOCA signal.	PE/LK - Reactor Operator opened a breaker during troubleshooting and did not know what components would be affected by operating this breaker.	OPS
03/16/87	87-18	TS violation: Inoperable fire rated floor.	PE/ID - Floor penetration was not properly resealed after a temporary line was removed.	ENG/TS
04/18/87	87-19	Partial Primary Containment Isolation: Instrument air, RBCLC, and recirculation hydraulics isolated on loss of Division I Emergency DC Power.	PE/PJ - Reactor Operator, while performing a tagout, isolated the battery from the bus prior to returning a battery charger to operation. Power was lost when neither battery charger or the battery was aligned to the bus.	OPS
04/22/87	87-20	Spurious Rx scram, turbine and feedwater pump trip (no trip) during surveillance testing. Reactor vessel Level 3 amd Level 8 trip.	EM/DD - The reactor vessel level detectors are too sensitive to pressure spikes on instrument lines. In this case, a detector was being returned to service.	ENG/TS
04/30/87	87-21	Potential failure of Clow butterfly valves due to movement of spline adaptor.	EM/DD - Valve stem to operator linkage set screw loosened during valve operation.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
05/02/87	87-22	Partial Primary Containment Isolation and Auto Start of Control Building special filter train. Instrument Air, RBCLC and Recirculation Hydraulics Isolated. Loss of Division II Emergency DC Power.	PROE - The procedure for recharging the battery was not clear as to how the charger should be placed onto the battery.	SURV
			PE/LK - Personnel returning the battery to service were not properly trained in the operation of the battery charger.	SURV
05/09/87	87-23	Partial Primary Containment Isolation: Shutdown Cooling isolation while isolating a High Rx pressure detector.	PE/LK - The person isolating the detector was not properly trained in the method to use.	SURV
			PROE - The procedure for isolating the detector was not specific as to the order in which to shut the isolation valves.	SURV
05/17/87	87-24	Two Secondary Containment Isolations/ Auto Starts of SBGT: Low Reactor Building normal ventilation flow.	EM/DD - Flow switch setpoints were set to close to normal air flow allowing unwanted system isolations when switching exhaust fans.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
05/19/87	87-25	Secondary Containment Isolation during during surveillance testing: Low reactor building normal ventilation flow.	PE/ID - A lifted lead was reconnected before it was required to be by the procedure. This was due to a communication breakdown.	SURV
05/25/87	87-26	Partial Primary Containment Isolation: RWCU isolation during venting of letdown flow detector.	PE/ID - Reactor operators allowed a detector to be vented which caused: a detector in parallel with the detector being vented to initiate a high differential pressure isolation.	OPS
			EM/DD - The RWCU letdown flow transmitters were located downstream of the flow control valve, this causes flow indication instabilities.	ENG/TS
05/25/87	87-27	TS Violation: SBGT drywell vent and purge radiation monitor operable.	EM/DD - The monitor sample pump was not designed to automatically start when SBGT flow began.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
05/22/87	87-28	TS Violation: DW personnel air lock inter door equalizing valve was not properly leak tested.	PE/ID - When preparing the test procedure and review leak test results, it results, it was not discovered that the interdoor equalizing valve was not being tested.	SURV
			EM/DD - The inter door equalizing valve could not be tested from outside of the drywell.	ENG/TS
06/03/87	87-29	Secondary Containment Isolation/SBGT Auto Start: Low Reactor Building normal ventilation flow.	EM/R - Use of hand held radios near circuitry caused a reactor building low flow instrument to spuriously isolate the normal ventilation and the start of SBGT.	ENG/TS
05/28/87	87-30	Numerous Partial Containment Isolations: Drywell purge and vent valve isolation due to loss of SBGT radiation monitoring capability. See LER 87-27.	PE/LK - A modification was installed forcing the sample pump to operate at all times. The modifications caused temperature problems within the radiation monitor cabinet. This caused the monitor to fail. The cabinet modification did not receive a safety evaluation before it was installed.	MAINT

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
06/12/87	87-31 X	Rx Scram: High IRM Flux Scram due to failed feedwater control valve causing a cold water injection transient	EF/DD - The feedwater level control valve mechanical position feedback arm disengaged causing the valve to fail open.	MAINT
06/12/87	87-32	Partial Priamary Containment Isolation: RWCU isolation while removing a filter demineralizer from service.	EM/DD - The RWCU letdown flow transmitters located downstream of the flow control valve, this causes flow indication instabilities.	ENG/TS
			EM/DD - Sensing Lines and valves were oriented to allow air trapping.	ENG/TS
06/15/87	87-33	Automatic Rod Insertion and Reactor Scram during Redundant Reactivity Control System (RRCS) testing. Spurious RRCS high pressure signals and subsequent scram discharge volume high level scram.	EM/R - A spurious signal was generated during surveillance testing.	SURV
			PROE - The surveillance procedure required an elapse time which was too long prior to resetting a trip signal.	SURV
06/17/87	87-34	Recirc pumps trip during RRCS testing.	EM/R - During troubleshooting energizing and deengergizing the system caused spurious signals.	SURV

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
06/18/87	87-35	TS Violation: Firewatch suspended when still required.	PE/ID - Fireman secure a watch prior to restoring a detector to service.	OPS
07/25/87	87-36	Two Secondary Containment Isolations/SBGT auto start signal Low normal reactor building ventilation flow.	PE/ID - I&C technician grounded a jumper during a normal PB ventilation radiation monitor surveillance, causing a damper to reposition and a low flow condition.	SURV
			ICA - The licensee failed to correct the problems with the use of jumpers during these surveillance tests.	ENG/TS
			PE/ID - Nonlicensed operator started RBV exhaust fans, as specified in system operating procedures.	OPS
			PROE - The procedure for operating RBV is not as clear as possible when describing the need to start exhaust and supply fans simultaneously.	OPS
06/22/87	87-37	Main steam tunnel differential temperature isolation instrument inoperable.	EM/DD - Two of the four ventilation inlet temperature detectors were not properly located to give proper delta T indication and isolation functions.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
08/07/87	87-38	Partial Primary Containment isolation: RCIC isolated on spurious steam line high differential pressure during RHR steam condensing mode testing.	EM/DD - Setpoint was found to be restricted since it allowed pressure isolations, caused by RHR steam condensing mode to to cause an RCIC isolation.	ENG/TS
06/30/87	87-39	TS Violation: Emergency Diesel Generator inoperable due to removal of diesel room ventilation fan from service.	PE/ID - Senior Licensed Operator removed one of the two 50% capacity Diesel room fans from service with a tag out and did not realize that by Technical Specifications, the diesel would have to be declared inoperable.	OPS
07/03/87	87-40	Secondary containment integrity not met due to inconsistent assumptions used when calculating SBGT drawdown time.	EM/DD - Design assumptions for SBGT draw down time were never incorporated into operating procedures.	ENG/TS
07/11/87	87-41	TS Violation: Failure to increase surveillance frequency of service water inlet temperature.	PROE - The shift check procedure did not contain the requirement that when service water temperature reached 74 degree F, the temperature monitoring frequency be increased to once every two hours.	OPS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
06/14/87	87-42	Partial Primary Containment Isolation: RWCU isolation due to flow oscillation while adjusting letdown flow to the condenser.	PROE - The procedure being used was not clear as to how to control reactor vessel level.	OPS
			EM/DD - The RWCU isolation instruments are too sensitive to flow instabilities.	ENG/TS
07/11/87	87-43 X	Rx Scram: High Reactor Pressure Scram.	EF/DD - EHC tubing was not designed to take the vibratory stresses that were imposed. The tubing ruptured and bypass and turbine stop valves shut.	ENG/TS
07/25/87	87-44	Plant shutdown required by Tech Specs: Service water temperature exceeded the TS limit for greater than 8 hours.	PE/PJ - The licensee did not expect lake temperature to go above 77 degree F when the emergency TS change to raise the limit from 76 to 77 was proposed.	ENG/TS
07/29/87	87-45	Two Secondary Containment Isolations/ Auto Start of SBGT.	PE/PJ - A Senior Reactor Operator failed to realize that two surveillances he allowed to be performed concurrently were not compatible.	OPS
			PE/ID - Reactor Operator did not follow operating procedures when returning normal ventilation to service.	OPS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
07/29/87	87-46	TS Violation: APRM testing not completed prior entering Mode 1.	PROE - The procedure for APRM surveillance did not include the surveillance on the APRM flow b upscale trip and mod blocks.	SURV
			PE/ID - Supervisory I&C personnel allowed these steps to be removed during earlier testing, but did not ensure they were put back prior to entry into Mode 1.	SURV
08/06/87	87-47	Two Partial Primary Containment isolations RWCU isolation due to flow oscillations	EM/DD - The RWCU letdown flow transmitters were located downstream of the flow control valve, this causes flow indication instabilities.	ENG/TS
			EM/DD - The flow element was located in a section of pipe that was sensitive to flow differences depending on where reject flow was was being sent.	ENG/TS
			EM/DD - Sensing Lines and valves were oriented to allow air trapping.	ENG/TS
			EM/DD - The RWCU isolation instruments are too sensitive to flow instabilities.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
08/09/87	87-48	Partial Primary Containment Isolation: Shutdown cooling isolation.	PROE - The procedure for transfering control of R from the remote shutdown panel to the Control Room did not specify resetting the high pressure SDC isolation signal.	OPS
08/25/87	87-49	Two Secondary Containment Isolation/Auto Start of SBGT	PE/ID - Reactor Operator failed to follow operation procedures when returning normal reactor building ventilation to service.	OPS
			EM/R - Normal reactor building exhaust fan trip with no apparent cause.	ENG/TS
08/29/87	87-50	Auto Start of SBGT.	PE/ID - Reactor Operator failed to ensure that SBGT was placed in PTL prior to authorizing surveillance on normal RB rod monitor.	OPS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
08/13/87	87-51 X	TS Violation: Failure to restore shutdown cooling to the core within one hour after loss of circulation.	PE/LK - Operators did not know that shutdown cooling was designed to isolate on loss of either divisional Reactor Protection Nuclear Supply (RPS/NS4) shutoff system power supplies.	OPS
			PE/PJ - Operators tried to restore power supply, which was not done within one hour, and did not take action to manually open SDC isolation valves to reestablish core cooling within one hour.	OPS
			EM/DD - RPS/NS4 divisional power supplies must be deenergized to allow testing of the power supply's Electrical Protection Assemblies.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
09/02/87	87-52	TS Violation: SBGT train surveillances for filter sampling was not taken at the required frequency, causing the train to be inoperable and required plant shutdown.	ICA - The licensee was told of a problem with calculating the run times for SBGT filter trains during the Readiness Assessment Team Inspection. No action was taken allowing this violation.	OPS
			PE/LK - Senior License Operator did not have the knowledge of the of SBGT train and was relying on the trains operablility to satisfy another TS required LCO for diesel generator operablility.	SURV
09/03/87	87-53	Partial Primary Containment Isolation: RWCU isolation due to spurious high flow differential signal.	EM/DD - The RWCU letdown flow transmitters were located downstream of the flow control valve, this causes flow indication instabilities.	ENG/TS
			EM/DD - The flow element was located in a section of pipe that was sensitive to flow differences depending on where reject flow was was being sent.	ENG/TS
			EM/DD - Sensing Lines and valves were oriented to allow air trapping.	ENG/TS
			EM/DD - The RWCU isolation instruments are too sensitive to flow instabilities.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
09/09/87	87-54	Partial Primary Containment Isolation: MSIV Trip Signal generated during surveillance testing.	PROE- The surveillance procedure did not ensure that operators were told to clear any generated isolation signals after performance of stop valve testing.	SURV
			ICA - The licensee did not review other procedures which cycle turbine when this first of event occurred on 1/26/87 (LER 87-09) in the previous SALP period.	SURV
			EM/DD - There are no annunciations in the control room to inform the operator of an isolation signal.	ENG/TS
09/16/87	87-55	Primary Containment isolation, due to a mistaken lead during surveillance testing.	PE/ID - The I&C Tech lifted the wrong lead while performing high area temperature system isolation function testing.	SURV

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
09/25/87	87-56	TS Violation: Gaseous Effluent Monitor Control Room annunciators do not have reflash capability for system trouble conditions.	EM/DD - Annunciators were not designed to have reflash capabilities as required by Tech Specs.	ENG/TS
09/21/87	87-57	Primary Containment isolation, shutdown cooling isolation and signal during surveillance testing.	PE/ID - I&C technicians failed to follow surveillance test when performing high area temperature system isolations, by not bypassing the isolation signal prior to generating another isolation signal.	SURV
10/01/87	87-58 X	Rx Scram: High IRM flux scram due to excess cold feed water injection.	PE/LK - Operator tried to use feedwater pump bypass valve to throttle flow to the vessel level. This valve is not a throttle valve and when opened, caused a cold water power excursion.	OPS
09/30/87	87-59	TS Violation: Nine TS required shift checks not not performed since license issue.	PE/ID - The operator shift check procedure did not include these nine items which are specified in TS because they were left out or deleted from the procedure.	OPS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
10/22/87	87-60	TS Violation: Missed TS required shift checks.	PE/ID - Reactor Operator failed to complete twelve required channel checks for various radiation monitoring instruments.	OPS
			PE/ID - Senior licensed operator failed to properly review surveillance test results prior to concluding that the surveillance had been successfully completed.	OPS
10/01/87	87-61	TS Violation: Failure to take proper compensatory action when primary containment leak rate monitoring systems were inoperable.	PE/ID - Chemistry Department did not take the proper samples.	RAD
10/08/87	87-62	TS Violation: Rx mode change with LPCS inoperable.	PE/ID - Reactor Operator performing the LPCS pump surveillance did not properly record test data.	OPS
			PE/ID - The surveillance test results were reviewed by a Senior Operator and Operations documented as acceptable.	OPS
10/13/87	87-63	Partial Primary Containment Isolation: RWCU due to high differential flow.	ICA - Previous actions taken to prevent these flow oscilations from from causing isolations were not adequate.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
10/23/87	87-64	Rx scram: Turbine trip caused by loss of condenser vacuum.	PE/ID - Licensed operator did not properly review tagouts allowing work to cause loss of vacuum.	OPS
10/15/87	87-65	Failure to maintain .25 inches of vacuum water gauge on Reactor Building.	EM/DD - The differential pressure instruments which control SBGT and Normal Reactor Building ventilation to maintain the required differential pressure were located such that pressures were sensed low in the Reactor Building. Given a low outside temperature, the difference in air density inside and outside the Reactor Building could cause an actual positive pressure near the top of the Reactor Building.	ENG/TS
10/20/87	87-66	TS Violation: Rx mode change with SLC inoperable.	PROE - GE documentation for SLC fuses specified improper replacement fuses for SLC piping circuit.	ENG/TS
			PE/ID - Reactor operator did not properly verify that the fuses installed were of the same amp ratings as the blown fuses.	OPS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
10/23/87	87-67 B	TS Violation: Limiting condition for operation of of main steam line radiation monitors misinterpreted.	PE/PJ - Senior Reactor Operator failed to realize that when one NS line rod monitor became inoperable TS required action to be taken.	OPS
10/20/87	87-68	Partial Primary containment isolation - RWCU isolation due to surveillance testing.	ICA - Action taken by licensee, based on LER 87-57, was not adequate to prevent this occurrence.	ENG/TS
			PE/ID I&C technician failed to follow surveillance test when performing high area temperature system isolation, by not passing the isolation signal prior to generating an isolation signal.	SURV
10/23/87	87-69 B	Secondary and partial primary containment isolation: SBGT autostart, SDC isolation and inboard group 2 thru 4 and 7 thru 9 isolation due to loss of RPS/NS4 Division 2 power supply.	PE/LK - Licensed Operator was not familiar with the operation of the nonclass IE interruptable power supply and caused transfer to a dead alternate power supply.	OPS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
	87-70	TS Violation: Primary containment emergency escape airlock outer door inoperable and proper TS required action not followed.	EM/DD - The outer door equalizing valve positioning mechanism allowed the valve to be open when it should have been shut.	ENG/TS
11/12/87	87-71	Partial Primary Containment isolation: RCIC isolation and signal during surveillance testing.	PE/ID - During performance of surveillance test of high area temperature system isolations, a technician bumped an instrument and caused the isolation signal.	SURV
			EM/DD - The area in which this test is performed is cramped and does not lend itself to easy performance of lead lifting as required by the procedure.	ENG/TS
10/28/87	87-72	Secondary Containment isolation and SBGT Auto Start, during ground isolation.	PROE - The procedure for DC power distribution did not provide instruction on what would be affected by a ground isolation procedure.	OPS
			PE/ID - Licensed operators failed to make a determination of what components would be affected when DC power was isolated.	OPS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
11/24/87	87-73	Partial Primary Containment Isolation. RWCU isolation: during differential flow detector maintenance.	PE/ID - Licensed Operator bypassed the wrong isolation signal when told to bypass both divisions of RWCU differential flow, he bypassed only one division of RWCU and one division of RCIC. The operator did not verify that the expected computer alarms had occurred.	OPS
12/19/87	87-74	Appendix R Violation: Inoperable fire rated floor plug in Division 2 Ventilation Room.	EM/DD - The contractors installation failed to meet fire rating requirements.	ENG/TS
			PE/ID - The plug had been breached since initial installation and not properly resealed.	ENG/TS
11/28/87	87-75	Rupture of "A" condensate storage tank and and failure of reactor building penetration seal.	EF/CD - The fiberglass tank was constructed on a nonlevel floor, such that it was not set on a foundation as designed. This caused high stresses in the area where the break occurred.	ENG/TS
			EF/CD - The boot type seal was apparently damaged by personnel working in the area. This lead to the failure.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
12/12/87	87-76	Potential Radioactive Release path through floor drain system.	EM/DD - The floor drain system in the Main Steam Tunnel was interconnected with other area drains such that if a MS break developed, radioactive steam and water could be forced through the drain system and potentially effect safety related equipment in the cross-connecting areas.	ENG/TS
12/14/87	87-77	LPCS and LPCI spurious injection and Division I diesel start.	PE/ID - I&C technician operated a wrong valve after trying to drain a section of instrument tubing during maintenance.	MAINT
			EM/DD - Instrumentation drain valves are in poor locations and are not easily identified.	ENG/TS
			EM/DD - Instruments are too sensitive to short pressure spikes in instrument lines.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
12/20/87	87-78	Two Secondary Containment isolations and SBGT Auto Start signal.	PE/ID - Operator failed to properly position normal RB vent for switch during starting operations. This caused a supply fan to not start simultaneously with an exhaust fan. The operator then tripped all fans causing the isolation signal to be generated.	OPS
			PE/ID - Operator failed to use indication to verify that a supply fan had started and was running concurrent with an exhaust fan. The running exhaust fan caused a RB pressure fan trip which caused the isolation signal and SBGT auto start.	OPS
			ICA - The licensee failed to implement design modifications outlined in LER 87-49, to prevent these occurrences.	OPS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
12/20/87	87-79	Secondary Containment isolation and Auto Start of SBGT.	PE/ID - During surveillance testing of normal RB rad monitors, a technician dropped a jumper causing a short, a spurious high rad signal and secondary containment isolation and SBGT autostart.	SURV
			ICA - The problem with jumper installation during this surveillance has happened before and the licensee has been unable to prevent further occurrences.	ENG/TS
	87-80	Not Issued.		
12/26/87	87-81	Rx Scram: Turbine trip due to loss of condense vacuum.	EF/DD - Feedwater heater drain line penetration into the condenser cracked due to hydraulic transients on the line.	ENG/TS
12/29/87	87-82	Rx Scram: MSIV closed during startup.	PE/ID - While trying to place the reactor mode switch to the startup position, a licensed operator put the switch in the run position causing the MSIVs to close as designed on low steam pressure.	OPS
			EM/DD - The Reactor mode switch, due to the number of switches ganged is difficult to operate.	ENG/TS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
12/30/87	87-83	TS Violation: Missed surveillance during vessel heatup.	PE/ID - Operator failed to take data on reactor heatup during plant startup due to not following plant procedures.	OPS
			PE/PJ - Licensed operators did provide proper oversight of surveillance operations in the Control Room.	OPS
12/30/87	87-84 C	Auxiliary Gaseous Effluent radiation monitor inoperable when required by TS.	EF/DD - Sample pump return line has the potential for obstruction due to moisture causing sample pump to trip on high discharge pressure.	RAD
01/20/88	88-01	Rx Scram: Rx vessel low level due to loss of feedwater. Subsequent vessel overfill.	PE/ID - Nonlicensed operator failed to properly verify that one train of instrument air prefilters was inservice prior to isolating a prefilter.	OPS
			PE/ID - Operators failed to verify that actions being taken to shut feed control valve actually stopped flow to the vessel.	OPS
			PE/PJ - Licensed operators failed to provide adequate oversight and direction of actions being taken during the vessel overfill event.	OPS

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
01/20/88	88-02	Partial Primary Containment Isolation on high differential flow.	ICA - The licensee has established a task but has not been able to correct the problems with RWCU differential flow isolations.	ENG/TS
01/21/88	88-03	TS Violation: Failure to make a special report within 90 days after LPCI injection.	PE/LK - The requirement to submit a special report in TS was not known to exist.	ENG/TS
01/21/88	88-04	TS Violation: Primary containment isolation actuation instrument for reactor vessel level isolations were not set conservatively with respect to TS required setpoints.	PROE - The setpoints specified in the instrument calibration procedures were incorrect.	SURV
			PE/ID - The contractor who calculated the amperage trip setpoints for these detectors made a calculational error.	ENG/TS
			PE/ID - Licensee personnel did not adequately review the data provided by the contractor.	ENG/TS
01/26/88	88-05	Auxiliary Gaseous effluent radiation monitor was inoperable when required by TS.	PE/ID - Sampling pump tripped because the filter on the outlet clogged and was never cleaned as recommended by the manufacturer.	MAINT

SALP TABLE 3.2.
Unit 2 Summary of Licensee Reportable Events

Event Date	LER Number/ Cause Code *	Description	Cause Determined SALP Board	Functional Area
02/15/88	88-06	Partial Primary Containment Isolation: MSIV closure during surveillance testing.	PE/ID - Senior Reactor Operator allowed the turbine to be reset and turbine stop valves open causing MSIV closure signal.	OPS
			ICA - Operators did not receive effective training on these types of closures, after previous occurrences.	OPS
02/01/88	88-07	Partial Primary Containment Isolation. Shut down cooling isolation while backfilling a detector sensing line.	EM/R - Detector tripped during backfill of sensing lines.	MAINT
02/19/88	88-08	TS Violation: Main steam line radiation monitors set less conservative than the actual 100% power readings.	PE/LK - The data used to calculate the settings was not conservative.	ENG/TS
01/29/88	88-09	TS Violation: The setpoint for the CST low level section transfer to the suppression pool for HPCS was set below the TS limit.	PE/ID - The contractors work for calculating this setpoint was never completely checked by the licensee.	ENG/TS

TABLE 4.1

Unit 1 Enforcement Activities

A. Violations Versus Functional Area By Severity Level

Functional Area	No. of Violations in Each Severity Level LI *	V	IV	III	II	I	Total
Plant Operations	8		1				9
Radiological Controls	3	1		1			5
Maintenance							0
Surveillance							0
Emergency Preparedness							0
Security & Safeguards							0
Assurance of Quality							0
Licensing							0
Engineering and Technical Support	7	1		1			9
Training and/ Qualification Area							0
TOTAL	18	2	1	2			23

* LI - Licensee Identified Violations (No Notice of Violation issued because the five criteria of 10 CFR 2, Appendix C were satisfied.)

(TABLE 4.1. CONTINUED)

B. Summary

Inspection Number	Requirements	Severity Level	Functional Area	Brief Description
86-26	TS 3.1.8 TS 3.4.5 See LER 86-33	LI	Engineering Technical Support	RBCLC Heat Exchanger Inoperable.
86-26	TS 3.6.14.b See LER 86-34	LI	Rad Control	Failure to continuosly monitor radioactive release from the stack.
86-26	TS 3.4.0 See LER 86-35	IV	Operations	Reactor Building integrity violated by having both doors at an access point open at the same time.
87-01	TS 3.6.2 See LER 87-01	LI	Engineering Technical Support	APRM rod block and upscale flow based trips did not have a fixed clamp.
87-03	TS Table 4.6.15.b (1) See LER 87-05	LI	Rad Control	Analysis not performed on stack composite sample.
87-08	10 CFR 71.5	III	Rad Control	Inadequate preparation for shipment of Radioactive material.
87-10	TS Table 4.6.2.a.(9) (b) See LER 87-04	LI	Operations	Weekly surveillance testing for APRM missed.
87-10	TS 4.6.7.b.1 See LER 87-06	LI	Operations	Missed daily check of diesel fire pump air tank pressure.
87-10	TS 3.6.10.1 See LER 87-07	LI	Operations	Failure to meet requirements for a fire rated penetration.
87-10	TS 3.6.10.1 See LER 87-08	LI	Operations	Fire rated barrier contained nonqualified piping.
87-10	TS 3.2.6 See LER 87-09	LI	Engineering/ Technical Support	Vibration instrument not in compliance with ASME Section IX.

(TABLE 4.1. CONTINUED)

B. Summary

Inspection Number	Requirements	Severity Level	Functional Area	Brief Description
87-10	TS Table 4.5.15.2 See LER 87-10	LI	Radiation Protection	Failure to continously monitor radioactive releases from stack.
87-10	TS 4.1.7 See LER 87-11	LI	Engineering/ Technical Support	Failure to perform daily fuel surveillance.
87-11	10 CFR 50.55	V	Engineering/ Technical Support	The required experience level for a Level 2 visual examiner onsite were not per ANSI 45.2.6.
87-17	TS 6.11	V	Radiation Protection	Whole Body count intake quantity not properly calculated.
87-21	TS 3.2.6 See LER 87-17	LI	Engineering/ Technical Support	Failure to properly hydrostatically test a a modification due to improper drawings.
87-21	TS 6.8 See LER 87-18	LI	Engineering/ Technical Support	Procedure removed from master file without proper review.
87-21	TS 3.6.10.1 See LER 87-19	LI	Operations	Failure to identify unacceptable fire rated penetrations.
87-21	TS 3.6.10.1.c See LER 87-20	LI	Operations	Missed firewatch.
87-21	TS 3.1.7.e See LER 87-21	LI	Operations	Failure to reduce reactor power prior to isolating a recirculation loop.
87-21	TS 3.2.6.a See LER 87-27 and LER 88-01	III	Engineering/ Technical Support	Various violations of the ISI Program.

(TABLE 4.1. CONTINUED)

B. Summary

Inspection Number	Requirements	Severity Level	Functional Area	Brief Description
87-21	TS 3.2.6.a (1) see LER 87-26	LI	Engineering/ Technical Support	Proper preservice inspection of piping restraints not performed.
87-24	TS 2.1.1 See LER 87-22	LI	Operations	LSSS violated operations total core peaking factor.

TABLE 4.2

Unit 2 Enforcement Activities

A. Violations Versus Functional Area By Severity Level

Functional Area	No. of Violations in Each Severity Level LI *	V	IV	III	II	I	Total
Plant Operations	10	3	5				18
Radiological Controls	2						2
Maintenance							0
Surveillance	1						1
Emergency Preparedness							0
Security & Safeguards							0
Assurance of Quality							0
Licensing							0
Engineering and Technical Support	2	1	2				5
Training and/ Qualification							0
TOTALS	15	4	7	0	0	0	26

* LI - Licensee Identified Violations (No Notice of Violation issued because the five criteria of 10 CFR 2, Appendix C were satisfied.)

(TABLE 4.2. CONTINUED)

B. Summary

Inspection Number	Requirements	Severity Level	Functional Area	Brief Description
87-02	10 CFR 21	V	Engineering/ Technical Support	Failure to notify NRC within 5 days of determining a substantial safety hazard.
87-08	TS 6.8 see LER 87-14	V	Operations	Failure to follow operating procedures.
87-08	TS 3.3.7.11	LI	Rad Control	Four hour flow estimates not performed on effluent radiation monitors.
87-08	Fire Protection Program	LI	Operations	CO2 System rendered inoperable without a fire watch and a missed fire watch.
87-16	10 CFR 50 Appendix B	IV	Operations	Failure to perform a safety evaluation.
87-20	TS 3.8.1.1 see LER 87-39	LI	Operations	Emergency diesel generator inoperable due to removal of ventilation fan from source.
87-20	TS 3.3.7.8.b 3.7.2.a see LER 87-15	V	Operations	Failure to perform hourly fire watches when fire detection zones were inoperable.
87-20	TS 4.7.1.1.1.a. see LER 87-41	LI	Operations	Failure to increase surveillance frequency of service water inlet temperature.
87-25	10 CFR 50 Appendix B	IV	Engineering/ Technical Support	Improper review of radiographic film and documentation and dispostioning.

(TABLE 4.2. CONTINUED)

B. Summary

Inspection Number	Requirements	Severity Level	Functional Area	Brief Description
87-29	TS 3.3.1 See LER 87-46	LI	Surveillance	APRM flow bias upscale trip function surveillance not performed
87-29	TS 3.4.9.2 See LER 87-51	IV	Operations	Failure to restore forced core circulation within one hour.
87-29	N2-FDP-7, Section 8.4	V	Operations	Oil rags and oil puddles in Emergency Diesel Generator rooms.
87-32	TS 3.8.1.1.e See LER 87-52	IV	Operations	SBGT train operated greater than 720 hours without sampling.
87-32	10 CFR 50 Appendix B See LER 87-52	IV	Operations	Management knew of problems with tracking SBGT run times but failed to correct them.
87-37	Fire Protection Program	IV	Operations	Failure to deenergize valves that were required to be due to Appendix R determination.
87-37	Various TS See LER 87-60	LI	Operations	Various shift surveillance checks missed due to a procedure problem.
87-37	TS 3.3.2 See LER 87-59	LI	Rad Control	Grab samples not taken of drywell when other leakage monitors were inoperable.
87-39	Various TS See LER 87-60	LI	Operations	Various shift surveillance checks missed.

(TABLE 4.2. CONTINUED)

B. Summary

Inspection Number	Requirements	Severity Level	Functional Area	Brief Description
87-39	TS 3.0.4 See LER 87-62	LI	Operations	Mode change with LPCS inoperable.
87-39	TS 3.0.4 See LER 87-66	LI	Operations	Mode change with SLC inoperable.
87-39	TS 3.6.1.3 See LER 87-70	LI	Operations	Primary containment emergency escape air lock outer door inoperable.
87-39	TS 3.3.2 See LER 87-67	LI	Operations	Failure to realize the number of main steam line radiation monitors that were required to be operable.
87-42	Fire Protection Program	LI	Engineering/ Technical Support	Inoperable fire rated floor plug.
87-45	TS 4.4.6.1.1 TS 4.4.6.1.2 See LER 87-83	LI	Operations	Missed surveillance on vessel temperature during heatup.
87-45	TS 3.3.2 TS 3.3.3 See LER 88-04 LER 88-09	IV	Engineering/ Technical Support	Inoperable level instrumentation due to improperly performed calculations.
87-45	TS 3.5.1 (f) See LER 88-03	LI	Engineering/ Technical Support	Failure to make a special report within 90 days of LPCI injection.

ENCLOSURE 3

MEETING ATTENDEES

NAME	CO.	DEPT.
Mary Haughey	NRC	Project Manager NMP-2
Robert Capra	NRC	Director, Project Directorate I-1
William A. Cook	NRC	SR Resident Inspector
Jon R. Johnson	NRC	Projects Section Chief
William F. Kane	NRC	Director Div. Reactor Projects
William T. Russell	NRC	Regional Administrator
Edward C. Wenzinger, Sr.	NRC	Chief, Reactor Projects Br2
Wayne L. Schmidt	NRC	Resident Inspector
Charles S. Marshall	NRC	Senior Resident Inspector, Ginna
Robert A. Benedict	NRC	Project Mngr., NMP-1
Joseph P. Beratta	NMPC	MGR. Nuc. Security
Richard B. Abbott	NMPC	Station Supt. NMP-2
Thomas W. Roman	NMPC	Station Supt. NMP-1
C. V. Mangan	NMPC	Sr. V.P.
C. D. Terry	NMPC	V.P. NUc. Eng. & Lic.
W. J. Donlon	NMPC	Pres. N.M.P.C.
John M. Endries	NMPC	Exec. VP and Pres.-Elect
J. A. Perry	NMPC	VP-QA
T. J. Perkins	NMPC	VP-Nuclear
J. L. Willis	NMPC	Gen'l Supt. NMP
John T. Conway	NMPC	Supv. Sr. Analyst
J. R. Spadafore	NMPC	Tech Services
R. E. Jenkins	NMPC	Tech Support
W. C. Drews	NMPC	Technical Supt.
James Kuzniar	NMPC	Maint.
K. F. Zollitsch	NMPC	Supt. Training
G. F. Larizza	RG&E	Director, OPS Assessment
Kim A. Dahlberg	NMPC	Site Maint. Supt.
Charles L. Stuart	NMPC	Mgr. Nuc. Div. Projects
Robert G. Randall	NMPC	Operations Supt. Unit 1
Robert G. Smith	NMPC	Ops Supt. NMP2
Pat Volza	NMPC	Radiation Protection Mgr.
Edward Gordon	NMPC	Supv. Rad. Support
Don Wilcox	NMPC	Training Supv.
Randy Seifried	NMPC	Asst. Supv. Training
Doug Pike	NMPC	Mgr. - Audits & Reports
S. W. Wilczek, Jr.	NMPC	Manager Nuclear Technology
G. D. Wilson	NMPC	System Attorney
Mark J. Wetterhahn	Conner & Wetterhahn	Attorney
Greg Grezock	NMPC	Manager Nuclear Eng.
M. G. Pace	NMPC	Manager Materials Engr.
Richard Neild	NMPC	Tech. Asst. to Station Sup. U-2
R. A. Cushman	NMPC	Sr. Eng. Spec.-Nuc. Consulting
A. S. Kovac	NMPC	Mgr. QIP
Mitch Bullis	NMPC	Asst. Supv. Radwaste OPS II
Joe Snyder	NMPC	Construction Unit II
D. E. Sandwick	NMPC	Mgr. Engineering Services
J. J. Bebko	NMPC	Mgr. Nuc. Comp. & Verification
A. F. Zallnick	NMPC	Asst. to the Senior VP Nuclear

ATTENDEES LIST (Cont'd)

NAME	CO.	DEPT.
John Lasky	NMPC	Unit I Fire Prot.
T. Ganey	NMPC	Unit 1 & 2 Fire Dept.
Andrew R. Andersen	NMPC	Site Supervisor Fire Prot.
Jim Kinsley	NMPC	Unit Supv. I&C at U-2
Leslie Hart	NMPC	Unit II I&C
Louis Lagoe	NMPC	Site Supervisor I&C
M. J. Falise	NMPC	Supt. Mech. Maint.
P. Mazzaferro	NMPC	Asst. Supv. Tech Support
R. Devendorf	NMPC	Alt. Steward & Foreman
Paul C. Mangano	NMPC	Supervisor, Computer
Mike Randall	NMPC	CSO
B. R. Quinn	NMPC	CSO Unit 1
S. M. Brown	NMPC	CSO Unit 1
Ed Leach	NMPC	Princ. Gen. Spec. RP & Chem.
Al Smith	NMPC	Const. Supt. Unit 1
Jean DeSantis	NMPC	Admin. Services
Channel 9 News		

ATTENDEE LIST (Cont'd)

NAME	CO.	DEPT.
M. F. Cinadr	NYPSC	Staff
W. A. Hansen	NMPC	Mgr. Corporate QA
A. J. Combs	NMPC	Bldgs. & Grounds
John Woods	NMPC	Chemistry & Radiochemistry
John Lawton	NMPC	Chemistry & Radiochemistry
John Coates	NMPC	Chemistry & Radiochemistry
MaryAnn Biamonte	NMPC	Mngmt. Effect. Prog. Mngr.
John M. Sovie	NMPC	GET Training
Paul D. Eddy	NMPC	9 Mile Site Rep.
Scott C. Peer	NYSPSC	Elect. Maint. Unit 1
Dave Barrett	NMPC	Elect. Maint. Unit 2
Gary Gilmer	NMPC	Nuclear Security
P. D. MacEwan	NMPC	Site Rep.
Joe Manacuso	NYSEG	Unit II Oper.
John T. Pavel	NMPC	Asst. To V.P.-Nuclear
Charles Cary	NMPC	I&C Trng. Supv.
Manfred Brause	NMPC	Comp. & Verif. Lead
Robert E. Coon	NMPC	Nuclear Gen. Spec.
Ed Schaperjahn	NMPC	I&C/Unit 1
Y. Goyal	NMPC	Cost Dept.
R. J. Cohen	NMPC	Site Services
J. Kroehler	NMPC	Mgr. Qual. & Rel. Eng.
T. D. Lee	NMPC	Asst. Mgr. Mech. Design U-1
B. J. Murtha	NMPC	Station Shift Supv.
J. L. Dillon	NMPC	QA Audit Supervisor
W. A. Mosher	NMPC	Admin. Services
D. Lilly	NMPC	S.S.S.
J. C. Aldrich	NMPC	OPS Unit #1
H. T. Barrett	NMPC	Prog. Mgr. Root Cause/Trend.
Geo. S. Shelling	NMPC	SSS Unit #1
Thomas J. Chwalek	NMPC	Emergency Planning Coord.
Alan DeGracia	NMPC	Unit II Operations
James Burr	NMPC	Unit II Ops.
Edward Delaney	NMPC	Unit II Ops.
Robert Bulluck	NMPC	Unit II Ops.
Mary L. Hujar	NMPC	Staff Serv.
Mary Kohlbrenner	NMPC	Unit #2 Mech. Design
Donald Cameron	NMPC	Unit #1 Stru. Design
Linda Edwards	NMPC	Unit #2 Records Mgt.-Steward
Marcia Hagen	NMPC	Unit 2 Recd's Mgmt
Charles Boniti	NMPC	Security
J. Beijen-Lukens	NMPC	Nuc. Engr. & Lic.
Jim Bunyan	NMPC	Nuc. Eng.
Joe Messina	NMPC	Nuc. Eng.
C. G. Beckham	NMPC	Mgr. Nuc. QA Operations
P. J. Carroll	NMPC	Security
Floyd Merry	NMPC	Unit #1 Mech. Design
Dennis McNally	NMPC	Unit Supv. Fire Prot.-Unit 2
Tom Perkins	NMPC	Unit #1 Fire Prot.
William Hopper	NMPC	Unit #2 Fire Prot.

ENCLOSURE 5

SALP BOARD REPORT ERRATA SHEET

Page	Line	Board Report	Amended Report
25	41	and review by the Engineering staff	deleted

Basis: The licensee did not commit to have all valve packing adjustment work requests reviewed by the Engineering staff.

Page	Line	Board Report
42	3-9	One notable exception was the failure of the licensee to discuss the significance of the May 18, 1987 letter on non-1E devices in Class 1E systems with the new Project Manager when it was submitted. Failure to emphasize the significance of this issue during the high activity period immediately before Unit 2 full power locensing, ultimately led to postponing the Commission Briefing.

Amended Report

However, the licensee needs to ensure that the NRC staff is alerted to items that require immediate attention. On May 18, 1987 the licensee submitted a failure modes and effects analysis for non-1E devices in 1E systems. While the NRC recognizes the licensee's initiative concerning the self-identification of this issue, the licensee should have discussed the significance of the issue with the new Project Manager when it was submitted. Failure to emphasize the significance of the issue during the high activity period immediately before Unit 2 full power licensing, delayed the identification of this issue as an item that needed to be resolved before full power licensing. This late identification led to a two week postponement in the issuance of the full power license.

Basis

To provide more background on licensee responsiveness to this critical licensing issue, but to also credit the licensee for their self-identification of the issue.

ENCLOSURE 5 (continued)

Page	Correction
T1-2 through T2-7	Due to a data entry error for the inspection hours for Inspection Report 50-410/87-16 in Table 1, several dependent inspection hour totals and percentages in Table 2 required correction.

Page	Correction
Various	Various typographical, spelling and grammatical errors were corrected throughout the report, but are not specifically annotated.

ENCLOSURE 2

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

21 APR 1988

Docket No. 50-220
Docket No. 50-410

Niagara Mohawk Power Corporation
ATTN: Mr. W. Donlon
President
301 Plainfield Road
Syracuse, New York 13212

Gentlemen:

Subject: Systematic Assessment of Licensee Performance (SALP): Report No. 50-220/86-99 and 50-410/87-99

The NRC SALP Board conducted a review on March 28, 1988 to evaluate the performance of activities associated with Nine Mile Point Unit 1 and 2. The results of this assessment are documented in the enclosed SALP Board Report. A meeting will be scheduled to discuss this assessment. This meeting is intended to provide a forum for candid discussions relating to your performance during the period.

As discussed in the current SALP Report and the prior separate Unit 1 and Unit 2 SALP Reports, Niagara Mohawk's initiatives to improve performance have met with limited success in some functional areas but have not been sustained in others. We believe that the examples, cited in this report, of lack of positive motivation and worker attitude, and the lack of effective coordination and cooperation between various station and corporate departments, have been significant contributing factors to your inability to sustain improved overall performance. At other Region I nuclear power plants, these symptoms have been precursors to more serious regulatory concerns.

Your recent actions to strengthen site management and build teamwork are positive steps; however, we remain concerned about leadership weaknesses and your staff's ability and propensity to seek out and correct technical and management problems before they become regulatory concerns.

At the meeting, you should be prepared to discuss our assessment and your plans to address those areas that require improved performance. In particular, you should be prepared to discuss your actions relative to the planned reorganization and management changes.

Any comments you may have regarding our report may be discussed at the meeting. Additionally, you may provide written comments within 30 days after the meeting.

8805030125
3pp.

We appreciate your cooperation.

Sincerely,

W T Russell

William T. Russell
Regional Administrator

Enclosure:
NRC SALP Board Report No. 50-220/86-99 and 50-410/87-99

cc w/encl:
C. Mangan, Senior Vice President
J. Endries, Executive Vice President
Connor & Wetterhahn
John W. Keib, Esquire
J. Perry, Vice President, Quality Assurance
T. Perkins, Vice President, Nuclear Generation
C. Terry, Vice President Nuclear Engineering and Licensing
J. Willis, General Station Superintendent
T. Roman, Station Superintendent, Unit 1
R. Abbott, Station Superintendent, Unit 2
W. Hansen, Manager Corporate Quality Assurance
C. Beckham Manager Nuclear Quality Assurance Operations
Department of Public Service, State of New York
Public Document Room (PDR)
Local Public Document Room (LPDR)
Nuclear Safety Information Center (NSIC)
NRC Resident Inspector
State of New York
Chairman Zech
Commissioner Roberts
Commissioner Rogers
Commissioner Bernthal
Commissioner Carr
K. Abraham (PAO)(14)

APR 21 1988

bcc w/encl:
Region I Docket Room (with concurrences)
Management Assistant, DRMA (W/o encl)
DRP Section Chief
Region I SLO
W. Johnston, DRS
Director, DRSS
J. Allan, RI
D. Holody, RI
Board Members
R. Capra, NRR
R. Benedict, NRR
M. Haughey, NRR
B. Clayton, EDO, Region I Coordinator
G. Matakas, DRP File, RI
E. Kelly, DRP, RI
H. Eichenholz

ENCLOSURE 4

NIAGARA MOHAWK

NIAGARA MOHAWK POWER CORPORATION/301 PLAINFIELD ROAD, SYRACUSE, N.Y. 13212/TELEPHONE (315) 474-1511

June 9, 1988
NMP1L 0266

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Re: Nine Mile Point Units 1 and 2
Docket Nos. 50-220 & 50-410
DPR-63 & NPF-69
Systematic Assessment of Licensee Performance

Gentlemen:

Attached are Niagara Mohawk's comments on the Systematic Assessment of Licensee Performance (SALP) Report dated April 21, 1988. These comments were discussed with you during our meeting on May 10, 1988.

As indicated during the meeting, Niagara Mohawk generally agrees with your assessment. We have a number of programs in place to address the areas cited by you as needing improvement. These have been previously discussed with you. We are also taking additional actions as described in the attached. We recognize that some of these programs are long term in nature and will require continual management oversite to assure success. As you indicated in your report, some limited success has been achieved, but other areas still need improvement. We are continuing our efforts in those areas.

As we proceed through the next assessment period, we will be evaluating our performance utilizing our Self Appraisal Team effort and our ongoing Special Evaluations of our Long Term programs. We would be pleased to meet with members of the NRC staff to discuss our findings relative to performance improvement. An appropriate time period may be approximately midway through the current assessment period or September, 1988.

Sincerely,

NIAGARA MOHAWK POWER CORPORATION

C.V. Mangan
Senior Vice President

CVM/mjd/svm
1461W
Enclosures
xc: Regional Administrator, Region I
Mr. R. A. Capra, Director
Mr. R. A. Benedict, Project Manager
Ms. M. F. Haughey, Project Manager
Mr. W. A. Cook, Resident Inspector
Records Management

8806150008

NIAGARA MOHAWK POWER CORPORATION

COMMENTS ON

NRC SALP

FOR

NINE MILE POINT UNITS 1 AND 2

REPORT NO. 50-220/86-99 and 50-410/87-99

JUNE 9, 1988

4063K

I. Summary

As indicated during our meeting on May 10, 1988, Niagara Mohawk generally agrees with your Systematic Assessment of Licensee Performance (SALP) Report dated April 21, 1988. Provided herein are our comments on the Report with emphasis on our plans for improving overall performance in those areas where recommendations were provided by the SALP Board. Also provided are our comments on several areas where we disagree with the Reports findings. These comments were discussed with you during the May 10 meeting.

II. Specific Comments and Response to Recommendations

Summarized herein are our specific comments and responses to the SALP Report. Also, in several areas we have provided additional clarifications for your consideration. The comments are provided to correspond to each of the performance areas found in the Report.

A. Operations

1. Independence of Operations

We recognize the need to eliminate complacency and the sense of independence from other departments. We are accomplishing this through our team building efforts within the Nuclear Division. Various teams have been established to address items such as the development of an Operator Code of Ethics and an improved Operator Requalification Training program that incorporates the Operators specific needs. Operations personnel are also now part of the Work Control Center at Unit 1 which helps to improve the interface and communications between Operations and other groups.

The Institute of Nuclear Power Operations (INPO) has been and will be used in the future to help improve our Operations interface. An INPO assist visit is scheduled for June to help identify additional methods to reduce Operator independence and strengthen teamwork.

2. Housekeeping

Several steps have been taken to improve housekeeping. Areas of the plant have been assigned to specific individuals who are responsible for housekeeping. These individuals are required to tour their assigned areas frequently and take action to correct noted housekeeping problems. Weekly Superintendent and General Superintendent tours are conducted. Deficiencies noted are recorded and followed. Housekeeping has improved recently and we expect further improvements.

3. Operating Logs

A weakness was identified at Unit 2 in that Operating data logs were not maintained by the auxiliary operators who make rounds in the plant. Operating logs on equipment such as diesel

generators have been developed, however, in general, auxiliary operators do not generate equipment operating logs on their rounds. Unit 2 was designed for automatic recording of plant data. Instrumented systems exist and data is collected via trend recorders or computer logs.

We are currently developing our system engineer program. System Engineers will participate in the analysis of system performance. One of the initial tasks of the System Engineers will be to re-evaluate which equipment requires operations logs and trending. From this evaluation, operating logs and trending activites will be implemented accordingly.

4. Procedural Compliance

We are continuing our efforts to improve in the area of procedural compliance. Our Long Term program for improving procedures is in progress. Weekly meetings between the Operations Superintendent and shift personnel in requalification emphasize items such as procedure and Technical Specification compliance. Overall procedure rewrites are ongoing for both units. Major programs are underway to rewrite the Administrative Procedures and Radiation Protection Procedures to, among other things, make them more user friendly. We are also implementing modifications, such as with the Standby Gas Treatment System, to reduce the potential for personnel error.

B. Radiological Controls and Chemistry

1. Review and Oversight of Radiological Work Activities

As indicated in the Report, we have made enhancements to address previously identified weaknesses. However we recognize, for the reasons stated below, that further improvement is needed in the review and oversight of radiological work activities.

The NRC observed that management oversight of ongoing work was inadequate during the refueling outage. These problems occurred during the initial phase of the outage, because a significant effort was required for the On-The-Job Training (OJT) and qualification of contractor and temporary Radiological Technicians. These problems could not be anticipated because of the rescheduling of the outage. However, Supervisory Technicians (Chiefs) were assigned to major work areas, to ensure adequate oversight of on-going work, and in 1987, plant supervisor tours were instituted in an effort to provide oversight of work activities in both units. These supervisors attended the INPO Observer Training Program to better help them perform this oversight function. As the early training and qualification efforts were completed, additional emphasis was given to oversight of ongoing work. This included daily Radiation Protection supervisor tours, and weekly Radiological Support management tours.

Also the information gained during the plant supervisor tours is now being trended in our Radiological Performance Monitoring Report. This trending program will also allow us to track the effectiveness of our corrective actions.

We are aggressively pursuing the timely implementation of corrective actions identified in the radiological area. For example, corrective action programs for internal dosimetry concerns, portal monitor concerns and hot particle programs have been reviewed and found acceptable to the NRC.

2. Unit 1 Non-Radiological Chemistry Area Improvements

Improvements are being pursued in the area of non-radiological water chemistry. A Corporate policy regarding water chemistry was issued in February 1987. An INPO Assist visit in 1988 resulted in recommendations to improve our non-radiological chemistry operations philosophies. Recommendations, which resulted from a self-initiated Corporate Assistance and Safety Review and Audit Board review of plant lay-up and control of plant chemicals, have strengthened the program. Modifications are currently underway at Unit 1 to replace conductivity instrumentation and dissolved oxygen instrumentation. Maintenance practices are being revised to address temperature control features; if these prove inadequate, modifications will be made. Existing practices at Unit 2 will be reviewed to assess demineralizer capacity requirements.

3. Restore GEMS at Unit 2

We have in place a project team to address the problems associated with the Unit 2 Gaseous Effluent Monitoring System (GEMS). The system has been pre-operationally tested, however, software changes are needed to make all aspects of the system functional. These are currently being addressed. We anticipate the system will be operational by July 31, 1988.

4. ALARA Review Program

We agree with the assessment of the ALARA Review Program. We are working to develop improved dose tracking systems to better identify the status of work in progress. Increased management attention will be directed to the ALARA program in an effort to provide heightened ALARA awareness. Improvements will be made in our tracking and reporting techniques to keep all workers and supervisors informed of site and task related ALARA performance.

The current Site Respiratory Protection Coordinator is also responsible for oversight of our ALARA Program. We plan to separate these two functions so that oversight of both programs will receive increased attention.

5. Performance Trends

As indicated above, we have in place programs to address the concerns outlined in the Report. Additionally, we have been

aggressive in addressing other radiological and chemistry area concerns. For example, due to our demineralizer operating practices, Unit 1 has an exceptionally low reactor water conductivity. The radwaste volume generated at Unit 1 in 1987 was 5769 cubic feet compared to the BWR Average of 20,000 - 25,000 cubic feet. We have significantly reduced the man rem exposure required for Control Rod Drive work from approximately 1900 mRem per drive in 1986 to approximately 1500 mRem per drive during the current outage at Unit 1. A "zero discharge" for liquid effluents at Unit 1 has been maintained. Pipe and tank replacements have helped to reduce Radwaste Operations exposure. An in-reactor stress corrosion cracking water chemistry test was performed at Unit 1 in 1987. Data generated will be used to develop a permanent Hydrogen Water Chemistry program for Unit 1. We have developed an aggressive "Hot Particle" program.

We believe these examples provide an indication that our Radiological Controls and Chemistry program is not declining in overall performance and we request that this assignment of a declining trend be reconsidered.

C. Maintenance

1. Root Cause Evaluations

As indicated in your Report, this area shows signs of improvement. The root cause evaluation area is one of our ongoing Long Term Programs. Initial program accomplishments include the development and implementation of Root Cause Determination Procedures. Lessons Learned books are updated to reflect root cause evaluation results. Analytical troubleshooting training is planned for first-line supervisors.

Continuation of our Long Term Program is expected to further improve our root cause evaluation capabilities.

2. Feedwater Control Valve Failure

The report indicates that the sticking feedwater control valve problem experienced earlier in the cycle at Unit 1 was a precursor to the failure that occured with the same valve shortly thereafter. However, as outlined in our report to you dated March 1, 1988, we have determined that these events were not related.

3. Engineering Review of Work Requests

The Report at Page 25 indicates that the Work Requests for future safety related valve packing adjustments will be reviewed by the engineering staff to ensure proper post-maintenance testing. However, to clarify this point, this review is only required for post-maintenance testing for certain containment isolation valves. Also, this review may not be required on each post-maintenance testing requirement if there exists a prior applicable generic review.

D. Surveillance

1. Strengthen Corporate Management oversight of the Surveillance Program

Improvements have been made and will continue to be made in the surveillance area. For example, in the case of the Standby Gas Treatment System missed surveillances, procedures have been revised to reduce the potential for personnel error. Design changes have been implemented to improve record keeping and surveillance compliance. Use of task teams has helped to solve the problems identified in the system. As indicated in Section II.A.3, we are currently developing the responsibilities for System Engineers. It is anticipated that the System Engineers will review surveillance data and trend key parameters to predict and prevent problems.

With regard to Unit 2, personnel changes have been made in our Operations Department. Weekly shift meetings between the Operations Superintendent and Operations staff has improved communication with regard to surveillance activities. A work control center is planned for Unit 2. This work control center will be similar to Unit 1 and will help to reduce the potential for missing surveillances. Further design changes are being considered to reduce the potential personnel errors during surveillance testing.

INPO's Human Performance Evaluation System methodology is being implemented. Approximately 50% of the Technical Support Staff has been trained on this methodology. Further training is planned in the third quarter of 1988. A Niagara Mohawk Staff member is chairman of the INPO Maintenance Human Performance Evaluation System Committee and a member of other Human Performance Evaluation System action committees. A full time Human Performance Evaluation System Coordinator will be part of the reorganized Technical Department.

In summary, the unit surveillance programs and procedures have been strengthened. Surveillances are both verified and tracked independently by individuals other than the action party assigned the surveillance. A Quality Assurance Operations Surveillance Program oversees both units. Engineering reviews at Unit 2 are identifying improvements that can be made to address human factor concerns.

E. Engineering

1. Inadequate Involvement of Engineering in the Resolution of ISI Program Concerns

As outlined in our letter of April 13, 1988, several concerns have been identified by Niagara Mohawk in our Unit 1 Inservice Inspection (ISI) program. We are aggressively pursuing resolution of these concerns and will resolve them prior to startup from the current outage.

We have already made several changes in the ISI program area, including reassignment of ISI personnel, identification of an ISI program manager, establishment of a multidisciplinary task force to support specific ISI areas, increasing oversight of contractor activities, and tracking of non-conformances by an independent group.

2. Contractor Oversight

We are improving our oversight of contractors in the ISI Program and other areas during outages. As part of our current reorganization, an Outage Projects Group will be established with specific responsibilities for oversight of outage activities.

3. Station-to-Engineering Interface

As part of the current reorganization, a permanent Site Engineering Group will be established at the Station. This group will be the primary interface between the station and Engineering for the resolution of day-to-day problems. Sufficient staffing will be provided to ensure resolution of problems. Face-to-face communications between Station personnel and Engineering will improve the overall interface. System Engineers will be primarily located in this group.

F. Security and Safeguards

We have no additional comments.

G. Emergency Preparedness

We have no additional comments.

H. Licensing

1. Additional Management Attention is Needed to Improve Licensing Performance

A senior level manager has been assigned to manage Niagara Mohawk's Licensing group. He reports directly to the Vice President Nuclear Engineering and Licensing. As part of the Nuclear Division reorganization, a Site Regulatory Compliance group has been established to improve the coordination of Licensing activities onsite. A Nuclear Division Commitment Tracking System is currently being implemented. The Nuclear Commitment Tracking System is designed to provide better control, accuracy and more timely responses to NRC related commitments. Finally, plans are currently being developed to improve the overall interface and communications between Niagara Mohawk and the NRC.

2. Use of Non 1E Devices in Class 1E Systems

The Report indicates that Niagara Mohawk failed to recognize the significance of this issue during the Unit 2 full power hearings

and this ultimately led to postponing the Commission briefing. As indicated during the SALP meeting, we feel we have been proactive in resolving this generic issue. The initial problem was identified by Niagara Mohawk Engineers and immediately elevated to senior management and NRC. We are continuing to pursue resolution of this generic issue. We feel that the SALP report does not properly reflect these actions.

I. Training

1. Audit the Requalification Training Program and Revise as Needed

As summarized in our letter of April 21, 1988 and our response to the confirmatory action letter, Niagara Mohawk has evaluated its requalification training program. Improvements have and will be implemented to enhance its overall effectiveness.

The requalification documentation has been reviewed and discrepancies have been corrected. A computer based record keeping system will be in place by the end of 1988 to better track training activities. In addition, a future Quality Assurance followup audit has been scheduled to assess the effectiveness of our activities to solve the identified documentation problems in this area.

2. Examine Training Needs and Incorporate Operator Needs

A joint Operations and Training team has been established to assess and evaluate Operator training needs. Several recommendations are currently being reviewed by management. The Self Assessment Team (SAT) findings also identified training related issues. These are also being evaluated by management for possible utilization.

J. Assurance of Quality

1. Complete the Reorganization and More Clearly Define Staff Responsibilities and Accountability

We are aggressively pursuing our reorganization of the Nuclear Division. A major effort has been in place to clearly define departmental roles and responsibilities as well as to identify voids and overlaps in group functions. This has been an ongoing part of our Long Term Program in the Management Effectiveness Area.

Several management changes have taken place over the past year. A new General Superintendent of Nuclear Generation has been hired from outside of Niagara Mohawk. He brings new perspectives and motivation to the Nuclear Division. Two new Superintendents of Operations are in place at Unit 1 and 2.

These changes will help to strengthen management oversight, improve station teamwork and address leadership concerns.

Additional improvements include:

- The implementation of Technical Specifications interpretation books.

- The utilization of INPO peer evaluations.

- Establishment of Nuclear Division goals.

- Senior level management meetings ("People to People").

- Management tours to address housekeeping concerns.

- Relocating the Senior Vice President to the Site.

In addition, we are looking into ways to strengthen Site Operations Review Committee and Safety Review and Audit Board reviews.

All of the above actions will result in better oversight and management of Nuclear Generation and Nuclear Engineering activities.

III. Conclusions

As indicated during the meeting, Niagara Mohawk generally agrees with your assessment. We have in place a number of programs to address the areas cited by you as needing improvement. These have been previously discussed with you. We recognize that some of these programs are long term in nature and will require continual management oversite to assure success. As you indicated in your Report, some limited success has been achieved, but other areas still need improvement. We are continuing our efforts in those areas. As we proceed through the next assessment period, we will be evaluating our performance utilizing our Self-Appraisal Team effort and our ongoing Special Evaluations of our Long Term Programs.