DIAGNOSTIC EVALUATION

TEAM REPORT

ON

PALISADES NUCLEAR GENERATING FACILITY

MARCH 14-25, 1994

AND

APRIL 18-22, 1994

U.S. Nuclear Regulatory Commission
Office for Analysis and Evaluation of Operational Data
Division of Operational Assessment
Diagnostic Evaluation and Incident Investigation Branch

OFFICE FOR ANALYSIS AND EVALUATION OF OPERATIONAL DATA
DIVISION OF OPERATIONAL ASSESSMENT

Licensee:	Consumers Power Company
Facility:	Palisades Nuclear Generating Facility
Location:	Palisades Site, County of Van Buren, State of Michigan
Docket No:	50-255
Evaluation Period:	March 14-25, 1994 April 18-22, 1994
Team Manager:	R.W. Cooper II
Administrative Assistant:	Laurette Moorin
Team Leaders:	Henry Bailey Ronald Lloyd Alan Madison Walter Rogers
Team Members:	Brian Bonser Melanie Miller Peter Prescott Sada Pullani John Thompson John Wilcox Peter Wilson
Contractors:	Sonja Haber Brian Haagensen James Leivo Spyros Traiforos

Submitted By: R.W. Cooper II 6/10/94

R.W. Cooper II, Team Manager — Date
Palisades Diagnostic Evaluation Team

Approved By: E L Jordan 6/10/94

Edward L. Jordan, Director — Date
Office for Analysis and Evaluation of Operational Data

CONTENTS

ABBREVIATIONS

AC	alternating current
ADV	atmospheric dump valves
AFW	auxiliary feedwater system
AEOD	Office for Analysis and Evaluation of Operational Data
AMMS	Advanced Maintenance Management System
AO	auxiliary operator
AOV	air-operated valve
ASME	American Society of Mechanical Engineers
CAC	containment air cooler
CAL	calibration sheet
CARB	Corrective Action Review Board
CCP	Configuration Control Project
CCW	component cooling water system
CEO	Chief Executive Officer
CFR	Code of Federal Regulations
CM	corrective maintenance
CO	control room operator
CPCo	Consumers Power Company
CR	control room
CST	condensate storage tank
CV	control valve
DBD	design basis documentation
DC	direct current
DE	diagnostic evaluation
DEH	digital electro-hydraulic
DET	Diagnostic Evaluation Team
DG	diesel generator
dp	differential pressure
DR	deficiency report
ECCS	emergency core cooling system
EDO	Executive Director for Operations
EDSFI	electrical distribution system functional inspection
EOP	emergency operating procedure
ER	event report
ESF	engineered safeguards features
FO	fuel oil
FSAR	final safety analysis report
GL	generic letter
HPES	Human Performance Evaluation System
I&C	Instrumentation and Controls
IN	information notice
IPE	individual plant examination
ISI	inservice inspection

IST	inservice testing
JCO	justification for continued operation
LAO	licensed auxiliary operator
LER	licensee event report
LLRT	local leak rate testing
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LPSI	low pressure safety injection
MIS	management information system
MOV	motor-operated valve
MSLB	main steam line break
MSL	main steam line
MSSV	main steam safety relief valve
NOD	Nuclear Operating Division
NECO	Nuclear Engineering and Construction
NPAD	Nuclear Performance Assessment Department
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
OER	operating experience review
OIR	Operations Information Report
PCS	primary coolant system
PM	preventive maintenance
PMWT	primary makeup water tank
PPAC	Periodic and Predetermined Activity Control
PPEP	Palisades Performance Enhancement Plan
PRA	probabilistic risk assessment
QV	quality verification
RB	reactor building
RCM	reliability-centered maintenance
RPS	reactor protection system
RV	reactor vessel
SALP	Systematic Assessment of Licensee Performance
SE	shift engineer
SFHM	spent fuel handling machine
SEP	Systematic Evaluation Program
SG	steam generator
SIRWT	safety injection and refueling water tank
SS	shift supervisor
STO	switching and tagging order
SW	service water system
TBV	turbine bypass valves

TD AFWP	turbine-driven auxiliary feedwater pump
TOL	thermal overload
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
USQ	unreviewed safety question
VM	vendor manual
VOTES	valve operation test evaluation system
VP	vice president
VPCNO	Vice President and Chief Nuclear Officer
VPNO	Vice President of Nuclear Operations
WO	work order
WR	work request

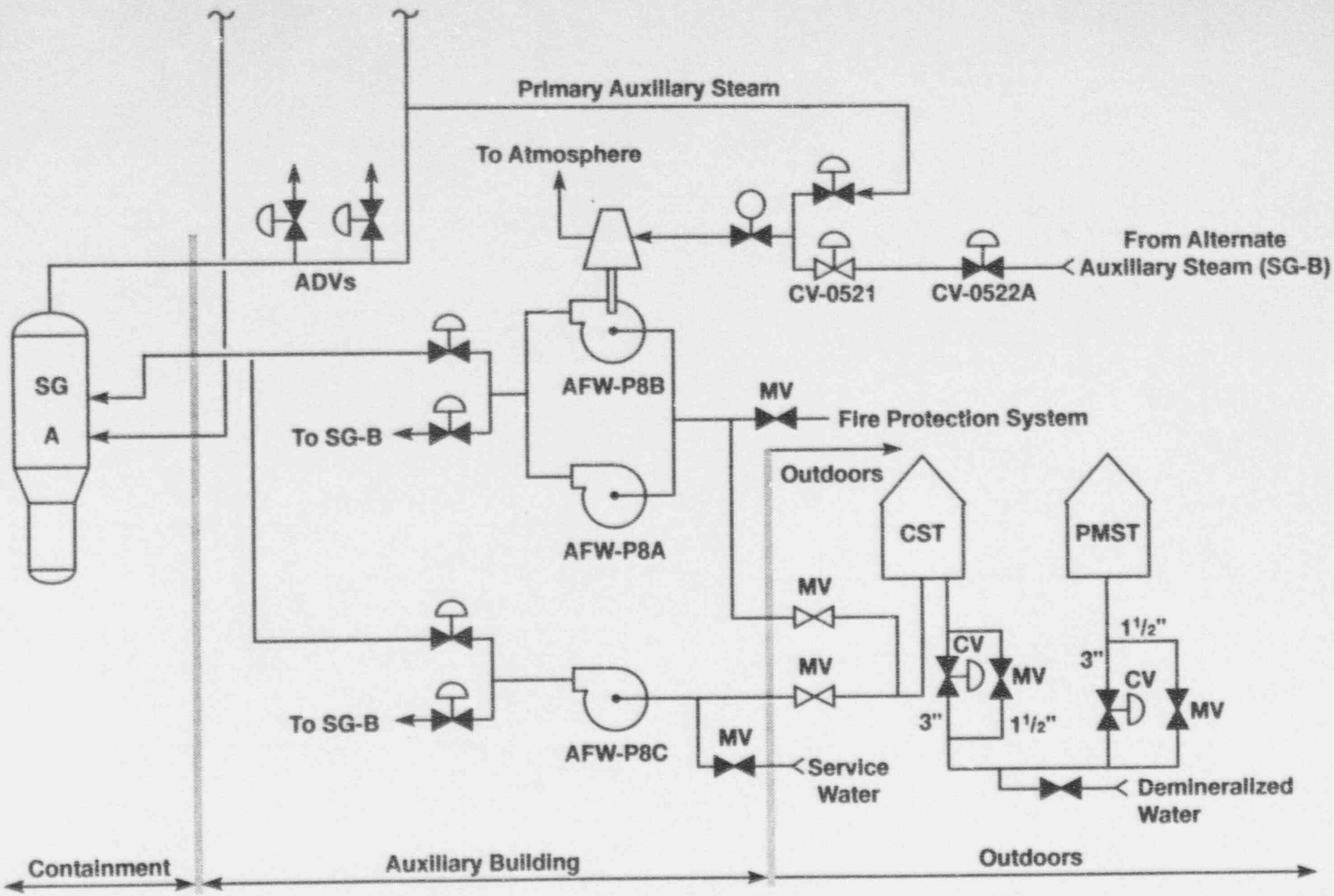


Figure 1
Auxiliary Feedwater System Schematic

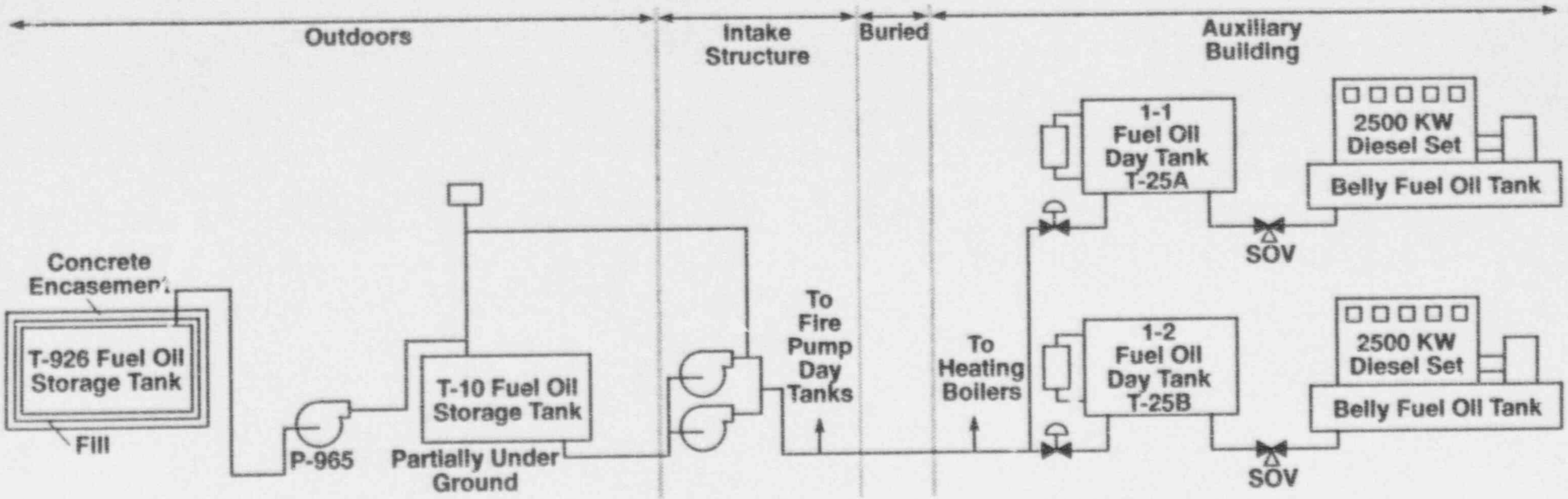


Figure 2
Diesel Engine Fuel Oil System Schematic

EXECUTIVE SUMMARY

From March 14 - April 22, 1994, a diagnostic evaluation team from the U.S. Nuclear Regulatory Commission evaluated the performance of Consumers Power Company in ensuring safe operation of the Palisades Nuclear Generating Facility. The evaluation was requested by the NRC Executive Director for Operations in order to obtain information needed to make an informed decision on overall performance at Palisades. The team, led by an NRC manager, consisted of 15 technical evaluators and an administrative assistant. Areas evaluated included operations and training, maintenance and testing, engineering and technical support, and management and organization. The facility was in a forced outage during the evaluation period. The Palisades senior management team was in transition just before and during the evaluation due to the replacement of several key managers.

Overall, the team found many performance weaknesses across the plant that had resulted in numerous operational events and instances of damaged or degraded equipment. These weaknesses also impacted the ability of some equipment and systems to function in accordance with their design bases. In some cases, the licensee had not identified the degraded conditions. In other cases, the licensee had incorrectly evaluated the impact of the conditions on safe plant operation, necessitating a re-evaluation to address the team's concerns. In still other cases, the licensee had not evaluated the conditions because it did not recognize the potential safety impact. The safety consequences of some degraded equipment and programmatic deficiencies were still under evaluation by the licensee at the issuance of this report. One of the most safety significant findings by the team was the excessive amount of material still inside containment that had been left there after closeout by the licensee following the 1993 refueling outage. The latter condition rendered the containment sump inoperable and required the licensee to remove the material prior to closeout of the containment following restart from the March 1994 forced outage. Although the majority of the remaining conditions were of lesser safety significance, the broad performance and programmatic weaknesses identified by the team had the potential to allow significant safety deficiencies to go undetected and uncorrected.

The team found that Operations management sometimes poorly planned or directed various plant evolutions, process controls, and job assignments that contributed to weak operator performance and operational events. Occasionally, onshift supervisors provided poor oversight and direction of facility activities. Supervisors not fully understanding their job responsibilities, limited supervisory training, and distractions in the control room contributed to problems with supervisory oversight. The extensive collateral duties assigned to onshift supervision also contributed to this weakness.

Operations management established low or incomplete expectations for operators and did not reinforce established expectations with onshift supervisors or operators. This included not fostering an environment of procedural adherence which contributed to operational events. Some other areas of low standards and expectations included procedure quality, control of extraneous material within containment, control of equipment temporarily positioned in the plant,

involvement of Operations in operability decisions, material deficiency reporting by auxiliary operators, and log keeping practices. Low standards of performance contributed to instances of inoperable or degraded safety-related equipment and operational events. Also, the lack of rigorous adherence to procedures combined with poor process controls caused repetitive personnel protective tagging problems over an extended period.

Engineering, Licensing, and Training poorly supported Operations causing or contributing to numerous performance problems and reducing operator capabilities to respond to operational events. Engineering provided ineffective and untimely resolution of design or material condition deficiencies, weak support for operability decisions, and poorly written surveillance testing procedures. Licensing contributed to complex and confusing technical guidance that made it difficult for operators to make conservative operating decisions. Weak training in certain areas contributed to operational events involving the spent fuel handling machine and operating the reactor at pressures prohibited by procedures while shutdown at low temperatures. Weak training in root cause analysis and NRC reporting requirements also affected Operations supervision performance in these areas. Except in select training areas, the Operations staff either tolerated or did not recognize poor support from other plant organizations.

Operations self assessments, as well as corrective actions to problems identified by these self assessments, were weak. This resulted in poor evaluations of human performance errors and operational events.

Positive Operations observations included management recognizing performance needed to improve. Before the team arrived, performance improved in the areas of spent fuel handling in the spent fuel pool and operating the reactor within allowable pressure and temperature operating regions. Other positive observations included extensive fire brigade training, daily reports to senior management on equipment deficiencies of highest concern to Operations management, and an information book on recent plant performance that was easily accessible to operators.

The team identified significant weaknesses in many areas of maintenance and testing. The team noted weaknesses in the licensee's testing program for demonstrating equipment operability. These included some test procedures that did not demonstrate the Technical Specification design function of the equipment or system being tested, acceptance of some test results that did not meet the acceptance criteria, and instances of poor root cause evaluations or operability determinations of testing failures. Weaknesses were also identified in the testing of pumps and valves. These included the licensee not confirming the acceptability of parameters and results for inservice testing of some pumps, not testing some important manual valves that were relied on in Emergency Operating Procedures, not leak rate testing some inservice testing category "A" valves, and not having a coordinated testing program for air-operated valves. In addition, the licensee had not clearly documented the relationship between the safety analysis and the stroke time values for many motor-operated and air-operated valves.

Weak supervisory oversight of maintenance work in progress contributed to continuing procedural adherence problems by maintenance workers, and sometimes allowed work to be performed without acquiring engineering support needed for completing the work appropriately, or for determining root causes of component failures. Maintenance workers and supervisors were not sensitized to look for and report plant material condition deficiencies, which resulted in many deficiencies existing uncorrected throughout the plant. This condition was caused by an incomplete implementation of established work processes, a fragmented and poorly implemented corrective action system, and the poorly implemented maintenance policy guidance that required area walkdowns by maintenance workers and supervisors. A number of degraded conditions or equipment failures that were identified resulted from ineffective or a lack of equipment preventive maintenance.

Numerous fundamental weaknesses in material control and supply of parts from the warehouse had the potential, if uncorrected, to degrade installed equipment or cause early component failure. The licensee's work control process exhibited weaknesses in tracking and reporting. Several work requests from mid-1993 for changing safety-related breaker and motor thermal overload settings had not been entered into the work request system by March 1994.

A positive observation in the Maintenance and Testing area was the detailed documentation of ongoing repair activities in work packages by maintenance workers. This allowed detailed material history to be available to the Maintenance and Engineering departments for performing root cause analysis of degraded or failed equipment.

In the area of engineering and technical support, the team determined that support to the plant from both the Nuclear Engineering and Construction Organization and Systems Engineering was often weak. The lack of well-defined roles and responsibilities of the two organizations, as well as the interfaces between them and with other plant departments, was a significant contributor to this weakness. In addition, authority was not very clear, accountability was not maintained, and standards and expectations were not well delineated or communicated to the organizations. Other significant contributors to weak engineering support were a historical lack of design basis information, a tendency to perform evaluations and institute administrative controls instead of correcting hardware deficiencies with modifications, and a lack of comprehensive understanding of the operability evaluation process. This led to instances of untimely and poor quality engineering evaluations in support of operability determinations for degraded equipment and instances of weak and untimely root cause determinations for failures of safety-related equipment. Poor engineering support for developing and revising plant operating and maintenance procedures resulted in instances of deficient procedures and untimely revisions which contributed to long-standing procedural adherence problems by Operations and Maintenance personnel. Poor oversight of contractors' work by Engineering, including ineffective technical reviews of some of the work produced by contractors, also resulted in weak engineering support to the plant, including instances of operating the plant outside of analyzed conditions.

The plant staff identified problems to Engineering; however, Engineering was often slow to evaluate them, recognize their safety significance, and effectively resolve them. In some cases, even after the safety significance was recognized, Engineering was slow to act. This situation existed due to management's failure to clearly define or rigorously enforce its standards and expectations, barriers to resolving problems in the corrective action process, and weak training of Engineering personnel in some areas.

Control of the design and implementation of plant modifications was sometimes deficient, resulting in modifications that did not achieve the intended result. Contributing causes to plant modification problems were ineffective quality verification technical reviews and ineffective post-modification control of plant configuration. The team found instances in which Engineering did not provide a balanced view to plant management and endorse modifications that they believed were the most effective way to resolve design problems or degraded conditions. This led to over-reliance on operator actions, in some cases, to compensate for these conditions. Despite the licensee's efforts to improve in the area of configuration control since 1986, weaknesses still existed in the program and its implementation.

A positive observation by the team was that Engineering used and field-verified dynamic computer models developed for alternating current loadflow and diesel generator accident load sequencing for analyzing events and evaluating loads on system equipment.

In the area of management and organization, the team identified significant weaknesses in many areas of the organization. Management oversight and control was ineffective because of a lack of integrated programs and processes and clearly defined roles and responsibilities. Fragmented management control systems, poorly defined programs, and lack of or conflicting expectations prevented successful implementation of performance improvement initiatives. Management often did not recognize broader performance issues, their root causes, and associated consequences. Many events were caused or exacerbated by a lack of guidance and clear direction from all levels of management. Management's failure to recognize and effectively correct broad performance issues also resulted in degraded material conditions. Additionally, numerous examples of poor housekeeping and degraded material conditions were identified by the team and the licensee during the evaluation, some of which had the potential to adversely impact equipment and system operability. Until recently the Palisades senior management team had been primarily composed of managers who had limited or no nuclear industry experience outside of Consumers Power Company. This lack of an outside perspective had contributed to the failure to recognize weak performance and programmatic ineffectiveness in several areas. In other cases, Palisades management did not accept the critical assessments of outside organizations and recognize and take ownership of problems, resulting in minimal action taken to correct those problems.

Fragmented systems or processes in planning, corrective actions, configuration control, and management information systems, coupled with poor communication, produced a lack of functional integration between departments and poor performance and teamwork. Lack of clearly defined roles and responsibilities, coupled with poor communication and conflicting expectations, led to performance weaknesses and unsuccessful implementation of performance improvements. Ineffective management oversight contributed to or caused performance problems and safety significant events during outages, power operation, and periods of transition between these operating modes.

Plant management failed to correct the continuing human performance problems despite numerous internal and external assessments that indicated that these problems prevented successful completion of activities and caused operational events. Plant management did not give a high priority to resolving human performance weaknesses, as illustrated by the lack of staff in the human performance evaluation and corrective actions areas. Human performance weaknesses continued to cause instances of poor procedural adherence, incorrect valve manipulations, safety tagging deficiencies, and configuration control problems across the plant. Management and supervisory skills were not methodically taught or developed despite numerous events caused by weaknesses in these skills. More broadly, the corrective action process was ineffective. A high threshold for identifying deficiencies coupled with a lack of problem recognition and identification, shallow root cause analysis, and ineffective or untimely corrective actions resulted in the licensee's failure to take decisive action on a wide range of safety issues.

Independent quality oversight and line organization self assessments were ineffective in identifying the performance problems at Palisades. The Nuclear Performance Assessment Department, Palisades' quality oversight group, performed weak assessments that lacked depth, detail, and insight. Furthermore, the Nuclear Performance Assessment Department was ineffective in raising problems and concerns to the appropriate managers to ensure adequate resolution. Plant departments performed limited self assessments, resulting in findings of minimal significance that did not facilitate broad performance improvements.

The team observed that the new Palisades senior management team appeared to have begun to introduce higher expectations and standards of performance. The new Palisades management team recognized and acknowledged the existence of significant performance problems at Palisades and had developed and begun to implement the integrated Palisades Performance Enhancement Plan to address them.

The team found the root causes of Palisades' performance to be management's (1) acceptance of low standards of performance, (2) failure to integrate processes and clarify and communicate roles and responsibilities, (3) failure to ensure effective self assessment and quality oversight, and (4) failure to develop and implement an effective corrective action process.

1.0 INTRODUCTION

1.1 BACKGROUND

Palisades came under close U. S. Nuclear Regulatory Commission (NRC) scrutiny in 1992 because of six reactor trips resulting from equipment failures, one of which involved the reactor protection system. Also, beginning in late 1992, personnel performance errors became more visible to the NRC. In 1993 the plant became more of a concern to NRC senior managers because of indications of weakness in licensee management, programs, and personnel performance aspects of operations.

Some events that occurred in the Summer and Fall 1993 raised concerns about Palisades' operational performance. These included violating procedures while handling a fuel bundle causing it to drop 6 inches (15 centimeters), lifting the reactor vessel head with a control rod still attached, and lifting a fuel assembly along with the upper guide structure (for the third time in the past 5 years) when disassembling the core. An Augmented Inspection Team (AIT) was dispatched to the site in July 1993 to investigate these problems and noted several procedural violations. These were committed primarily by poorly supervised contractors but, in several instances, licensee supervisors were present and did not intervene.

Some of the conclusions reached by the AIT were that the licensee lacked a questioning attitude, decisions were not made conservatively, management expectations were not effectively conveyed, and there were poor communications within the Operations Department. Many of these characteristics were also observed in events near the end of the extended outage in Fall 1993. These included exceeding cooldown limits when shutting down the plant due to a crack on the pressurizer power operated relief valve nozzle safe end. The licensee had indications of the crack through its Inservice Inspection (ISI) program, but discounted the indication as weld slag.

The licensee received a Category 3 rating in Operations and Engineering and a Category 2 in Maintenance and Plant Support in its most recent Systematic Assessment of Licensee Performance. Several key issues were raised, with the most prominent being an ineffective self assessment capability (both on site quality assurance and off site review committee), lack of a questioning attitude and inability to make conservative decisions within the engineering organizations, ineffective senior management presence on site, and discord in the Operations Department.

At the January 1994 NRC Senior Management Meeting, the regulatory and operating performance history of the Palisades plant was discussed. The senior managers concluded that additional information was needed to make an informed decision on overall performance at Palisades. The Executive

Director for Operations (EDO) directed the staff to obtain this information by conducting a diagnostic evaluation at Palisades.

The licensee made several key management changes before the team arrived at the site. In January 1994 M. Morris was assigned as President and Chief Executive Officer and D. Joos was assigned as Senior Vice President, Nuclear, Rates, and Marketing. In February 1994 R. Fenech was hired from outside CPCo and assigned as Vice President Nuclear Operations and located on site. While the team was conducting its evaluation on site in March 1994, T. Palmisano was assigned as General Plant Manager. Consequently, the Palisades senior management team was in transition just before and during the diagnostic evaluation. Also, the plant was in a forced outage for the entire period that the team was on site.

1.2 Scope and Objectives

The EDO directed the staff to perform a broadly structured evaluation to assess overall plant operations and the adequacy of the licensee's major programs for supporting safe plant operation. The goals of the diagnostic evaluation were to: (1) provide information to NRC senior managers to make a more informed assessment of plant safety performance, (2) determine causes for weak performance in the Operations and Engineering areas, (3) determine whether causes of poor performance during refueling outages also exist during periods of power operation, with the potential to adversely impact safe plant operation, (4) evaluate the effectiveness of the licensee's self assessment capability, (5) evaluate licensee management's involvement and effectiveness with respect to safe plant operation, and (6) evaluate the effectiveness of the licensee's improvement programs and plans.

1.3 Methodology

The diagnostic evaluation team consisted of 15 technical members and an administrative assistant and was organized with four team leaders reporting to a team manager. The team devoted several weeks to preparation that included team meetings and briefings by representatives from Region III, the Office of Nuclear Reactor Regulation (NRR), and the Office for Analysis and Evaluation of Operational Data. On March 14, 1994, the team began a 2 week evaluation of the facility and the corporate office. On April 11 the Operations and Training group returned to the site for a week of evaluation before the entire team returned to the site. The full team conducted the final week of evaluation at the plant from April 18-22, 1994. The NRC Resident Inspectors frequently attended team meetings at the site and gave the team technical advice. Representatives from the team met daily with their licensee counterparts to discuss team activities and observations.

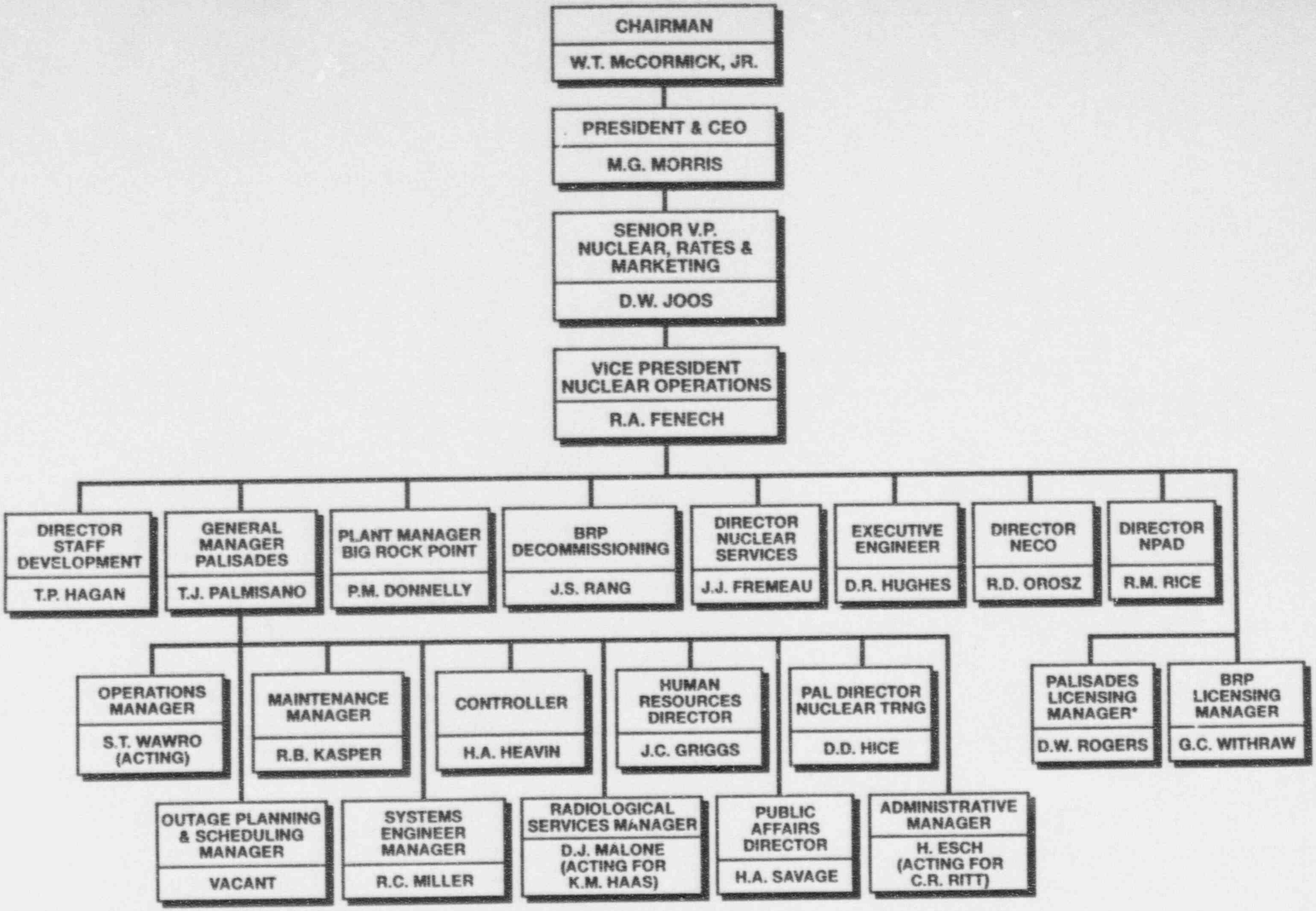
The team performed an in-depth assessment of the auxiliary feedwater and diesel generator systems (and their support systems) to gain insights into licensee performance of activities such as maintenance, testing, operation, and design control. The team placed special emphasis on identifying the causes of performance problems, and also assessed the licensee's performance in finding and correcting its own problems.

1.4 Facility Description

The Palisades Nuclear Generating Facility is located in the County of Van Buren, State of Michigan. The facility consists of one Combustion Engineering pressurized water reactor built by Bechtel as the prime contractor and architectural engineer. The unit was "turn-key", in that it was constructed and turned over to the owner after completion of a demonstration of unit operational capacity. The provisional operating license was issued on March 24, 1971.

1.5 Organization

The Palisades Nuclear Generating Facility is owned by CPCo. The following chart illustrates the CPCo organizational structure for management and support of Palisades at the close of the on site evaluation period.



*Palisades Licensing Manger reports directly to VP-NOD and indirectly to Palisades Plant Manager.

2.1 OPERATIONS AND TRAINING

The team found instances of poor planning and direction for various plant evolutions, process controls, and job assignments. Operations management established low or incomplete standards and expectations and did not reinforce established standards and expectations with onshift supervisors or operators. This included Operations management not fostering an environment of procedural adherence. Occasionally, onshift supervisors provided poor oversight and direction. The combination of poor process controls and the lack of rigorous adherence to procedures caused repetitive personnel protective tagging problems. Engineering, Licensing, and Training support to Operations was poor. Also, Operations self assessments as well as corrective actions to problems identified by these self assessments were weak.

Positive observations included management recognizing performance needed to improve. Before the team arrived, performance improved in the areas of spent fuel handling in the spent fuel pool and operating the reactor within allowable pressure and temperature operating regions. Other positive observations included extensive fire brigade training, daily reports to senior management on equipment deficiencies of highest concern to Operations management, and an information book on recent plant performance that was easily accessible to operators.

The team evaluated Operations performance during outages and previous power operations. The areas examined included management planning and direction, the scope and implementation of management expectations, onshift supervisory oversight and direction, equipment control and use, Operations staffing, effectiveness of internal performance assessments, support to Operations and Operations personnel training. Since the team did not witness the facility operating at power, a substantial number of formal interviews and document reviews were conducted to reasonably extrapolate performance at power. A combination of informal interviews, plant walkdowns and control room observations were also used by the team to evaluate Operations performance.

2.1.1 Poor Planning and Direction by Operations Management

Operations management poorly planned or directed various plant evolutions, process controls, and job assignments contributing to instances of poor operator performance and operational events. Examples included:

(1) As discussed in a licensee corrective action report, Operations management failed to properly plan and prepare for a pressurizer level change during a major maintenance evolution at power in January 1993. The lack of proper preparation significantly contributed to operating the reactor beyond analyzed limits for a few hours. A few hours before isolating the normal letdown and charging path to repair a leaking valve, the Operations Superintendent reviewed the operating procedure change to increase pressurizer level to the maximum normal operating limit and to establish an alternate charging path if pressurizer level dropped too low before re-establishing normal charging. However, instead of using the maximum normal operating limit, the Operations

Superintendent directed that the procedure change use the maximum pressurizer level permitted by the transient and accident analysis. Operations personnel informally contacted Engineering to get the maximum permissible level. Engineering did not review the procedure change and only verbally stated the maximum level in inches. Operations did not consider the difference in level instrument response from cold shutdown to normal operating temperature. Thus, Operations improperly converted level in inches to level in percent. Furthermore, the Licensing department's safety evaluation reviewer stated during a team interview, that his approval of the safety evaluation for this procedure change was based upon Operations technical reviewer's approval, not his independent evaluation. The licensee's corrective action report documented the haste in making the change as a contributor in establishing pressurizer level beyond previously analyzed limits. A few months afterwards, Engineering reevaluated the loss of load analysis using the higher level permitted by the procedure change and concluded the primary coolant system (PCS) design pressure would not have been exceeded.

(2) In May 1993, station management failed to properly prepare for flushing a hot radiation particle through a shutdown cooling heat exchanger drain valve and filter rig. At the conclusion of the flush the drain valve stuck open. Consequently, 6000 gallons (22,710 liters) of contaminated water spilled before the drain valve was closed, the integrity of the emergency core cooling water inventory was challenged, and two floors of the auxiliary building and five individuals were contaminated. Management did not ensure (1) appropriate temporary modification controls were used for the installation of the flush rig, (2) approved procedures for operation of the flush rig existed, (3) the most knowledgeable person involved in hot radiation particle flushing was assigned, or (4) contingency plans were developed should problems arise during the flushing.

(3) In an attempt to shorten the time required to perform control rod uncoupling activities, Operations management decided to perform the evolution with two tools and two teams. The 1993 control rod uncoupling training only familiarized some operators with the uncoupling tool and not how to perform the evolution using two teams. Also, the procedure for control rod uncoupling was not conducive to using two tools. These factors contributed to the crew not uncoupling one control rod in June 1993 and lifting that control rod with the reactor head during head removal. The positive reactivity addition of the removed control rod was offset by the high concentration of boron in the primary coolant system and the other control rods still in the reactor. Therefore, the removal of the control rod from the reactor minimally decreased the reactor's subcritical margin.

(4) Historically, control room operators (COs) exclusively held one of two positions within the control room: CO1 or CO2. The CO1 acted as shift foreman directing the auxiliary operators (AOs), operated balance of plant systems, interfaced with the offsite Power Control Department for actions in the switchyard, and processed tagging requests. The CO2 operated the reactor and PCS equipment, and performed most of the

Technical Specifications (TS) required surveillance tests. Once in the CO position, there was minimal incentive to progress into the supervisory ranks. Consequently, COs generally remained in their positions for many years with their skills developing along these specialized lines.

However, during the summer of 1993, the COs began periodically switching their CO1 and CO2 roles. Not only did this change affect control room duties, but it also affected fuel handling, since CO1s traditionally operated the reactor cavity fuel handling machine, and CO2s operated the spent fuel handling machine (SFHM).

Due to limitations on the number of onshift licensed staff (5 shift rotation), Operations management enabled select AOs to earn reactor operator licenses and periodically serve as CO2s in the control room. In 1991-2 these licensed auxiliary operators (LAOs) began periodically performing CO2 duties. Also in the summer of 1993, LAOs began serving as CO1s.

Operations management failed to compensate through additional training, coaching or supervisory oversight for these personnel performing unfamiliar licensed duties. This contributed to operator errors documented in licensee corrective action systems such as:

- In February 1994, an LAO, acting as a CO1, improperly processed a tagging request from the Power Control Department for the switchyard. The LAO failed to direct the AO to tag open certain disconnects.

- In September 1993, while in cold shutdown an experienced CO2 operator, acting in the CO1 role, did not properly perform a required surveillance test. The purpose of the surveillance was to assure all pressurized thermal shock protection controls were operable which included confirmation that the high pressure safety injection pumps could not inadvertently start. The CO only verified the power light indication to the high pressure safety injection pumps was not illuminated instead of verifying the power fuses were removed. Fortunately, the fuses had been previously removed and the next periodic performance of the surveillance properly confirmed the absence of the fuses.

- In January 1993, an LAO acting as a CO2 during one of the most difficult tests performed at power, QO-1, "Safety Injection System," failed to properly position control switches for two safety related valves and a component cooling water pump prior to test performance. When that section of the procedure was performed the valves did not change position and the pump automatically started. The pump was secured without incident and eventually the valves were successfully tested. This was the first time the LAO was in charge of conducting the test.

- During the 1993 refueling outage the SFHM mast hit a fuel bundle inspection table resting on top of the storage racks. Fortunately, there was no fuel grappled by the mast at the time. An LAO, inexperienced in operating the SFHM, was at the controls.

2.1.2 Occasionally Poor Onshift Supervisory Oversight and Direction

Based on document reviews and interviews the team determined that during some evolutions, onshift supervisors provided poor oversight and direction. The plant was shutdown with a minimal number of operating activities being performed while the team was on site. Although the team did not directly observe onshift supervisors providing poor oversight or direction, several causal factors contributing to this problem remained uncorrected. The causal factors included:

(1) Onshift supervisors did not fully understand their job responsibilities. There were two or three supervisors assigned to a shift with one of the supervisors always being the shift supervisor (SS). However, the two other supervisor positions, Operations Support Supervisor and Shift Engineer, were not fully staffed on each shift due primarily to a lack of accession of COs to those positions. The resulting delineation of roles and responsibilities among the three positions was not clear, especially the Shift Engineer position.

(2) Onshift supervisors received limited supervisory training and coaching.

(3) Operations management overburdened onshift supervisors with collateral duties that potentially distracted them from their licensed responsibilities.

(4) The location of a food preparation area in the control room was disruptive to onshift duties and the SS's cognizance of control room activities. Team members observed numerous non-essential personnel passing through the SS's office into the control room on day shift to obtain or prepare food. Also, the noise produced by the control room ventilation was distracting to control room personnel.

Examples of recent poor onshift supervisory oversight and direction documented in licensee corrective action reports and NRC inspection reports were:

(1) In several instances shift supervision performed only cursory reviews of surveillance test results. They did not verify that all the acceptance criteria were met. Consequently, test failures went unidentified for several days. For example, in January 1993 operators did not run a safety injection pump for the required five minutes before recording test data. A similar event occurred when operators tested an auxiliary feedwater pump in December 1993. Also, in May 1993 operators did not run the control room heating and air conditioning system long enough to meet the acceptance criteria. During the next scheduled performance of

these surveillances, the operators properly performed the tests and the equipment successfully passed the surveillance tests.

(2) In May 1993, the SS did not effectively review operating procedures concerning minimum reactor vessel temperature while the head was tensioned. He directed the COs to cool the PCS below the minimum temperature limit of 70°F while the head was tensioned. The SS stated in an interview with team members that he had been unsure of the minimum allowable temperature limit. (See Section 2.3.2(4) for additional information)

(3) In September 1993, the SS did not monitor, control or delineate control room responsibilities for plant cooldown in response to a PCS leak. Because of the urgency to depressurize the PCS, operators used an infrequently performed procedure for conducting the cooldown. The Shift Engineer and the Operations Support Supervisor assigned to the shift did not properly control this critical activity, in part because of their performing collateral duties and a lack of definition of job responsibilities. The operators exceeded the maximum allowable cooldown rate during the evolution. (See Section 2.3.2(4) for additional information)

(4) In May 1993, three SSs in succession failed to direct the COs to respond to a control room low hydrazine tank level annunciator. The plant's design had used hydrazine for containment iodine removal following a postulated accident. One of the two tank level instruments was indicating below the annunciator and TS limit. Also, operators did not question the alarm during shift turnover or take corrective action for three shifts.

2.1.3 Low Expectations of Performance by Operations Management

Operations management established low or incomplete standards and expectations for operators and did not reinforce established standards and expectations with onshift supervisors or operators. Some of the areas of low standards and expectations included procedure adherence and procedure quality, control of extraneous material within containment, control of transient equipment, involvement in operability decisions, material deficiency reporting by auxiliary operators, and log keeping practices. This contributed to inoperable or degraded safety related equipment and operational events.

Operators occasionally mispositioned safety-related components and damaged equipment. Also they routinely failed to maintain configuration control due to a lack of adherence to procedures and process controls. Furthermore, Operations management did not foster an environment of procedural adherence. This contributed to operational events documented in licensee corrective action reports and NRC inspection reports such as:

(1) In January 1993, during the performance of a surveillance test, a CO elected to close the alternate steam supply valve (CV-0521) for the turbine driven auxiliary feedwater pump. The procedure did not direct

this action. This action potentially rendered the alternate steam supply nonfunctional since this valve had a history of not opening on demand. The valve remained mispositioned for five shifts.

(2) On three occasions between July and August 1993, operators inadvertently rotated a main feedwater pump without its lube oil subsystem in operation, causing bearing failure. Operations management, in consultation with the SS, directed a change to a procedurally established system alignment without using a procedure change altering the established system alignment. Operations management and onshift supervision determined the valves could be manipulated without a procedure change because it was within the "skill of the craft."

(3) In March 1993, an operator, without onshift supervision permission, bypassed interlocks on the SFHM in an attempt to seat and ungrapple a fuel assembly that would not go in a storage location. This inappropriate action resulted in dropping the suspended fuel assembly 6 inches (15 centimeters) but did not breach the fuel cladding. Historically, onshift supervision did not maintain strict control over the override key bypassing SFHM interlocks. During previous years, minor events occurred where the SFHM cables unraveled due to misuse of the override key. Management and supervisory actions following those events did not ensure proper control and use of the override key. Also, it was not uncommon for the override key to be passed from CO to CO when extensive fuel handling occurred.

(4) In January 1993, an AO transferred main generator isophase bus duct cooling trains without using a procedure. As a result, the AO did not properly align the ducts causing an overheating condition. Subsequent operator response to the overheating condition was successful in preventing a generator trip and any damage to the isophase buses.

The procedure change process was ineffective and not integrated . Controls over operator data sheets did not include any independent review and approval. Responsibility for revising some of the procedures and operator data sheets was assigned to onshift supervision as a collateral duty. Consequently, procedures and operator data sheets were occasionally incomplete or incorrect. Although there were no safety consequences, these weaknesses resulted in configuration problems and deficient surveillance tests of safety-related equipment. Examples, half of which were identified by the team, included:

(1) In July 1993, Operations procedure writers did not revise the daily surveillance test procedure to include monitoring the diesel generator (DG) 1-1 fuel oil belly tank level after changing Standing Order 62 "Technical Specification Interpretations/Guidance." The revised standing order took credit for the quantity of the fuel in the belly tank to meet the minimum day tank level required by TS.

(2) In April 1992, Operations procedure writers revised system operating, abnormal and emergency operating procedures to direct operators to maintain the alternate steam supply valve to the turbine driven auxiliary feedwater pump in the open position. However, the governing

document for valve and breaker configuration, the system checklist, was not revised. Also, the piping and instrumentation diagram was not revised. This contributed to a January 1993 event when this valve remained mispositioned for five shifts.

(3) The SS inappropriately revised the operator data sheet for the maximum temperature limit for the condensate storage tank to 130°F. This temperature was outside the licensed maximum value described in the Updated Final Safety Analysis Report (UFSAR). There were no safety consequences as a result of this error since the tank remained below the UFSAR limit following the data sheet revision.

(4) In March 1994 onshift supervision did not revise the fuel oil transfer system checklist after revising the system operating procedure associated with non-safety related fuel oil transfer pump P-965. The revision to the system operating procedure changed the pump discharge valve from closed to open.

Despite numerous NRC generic communications on containment sump blockage, the team and later the licensee, found substantial amounts of unrestrained and extraneous material within the containment. Consequently, the licensee declared the sump inoperable due to potential blockage from the material. Containment tours by Operations management at the conclusion of and after the 1993 refueling outage never recognized or identified the inadequate containment closeout inspections. The written guidance on containment housekeeping contained vague criteria. The individual assigned to perform containment closeout inspections stated that removal of only 95% of the unrestrained and extraneous material was acceptable.

Operations supervision and personnel were generally unaware of administrative controls involving transient equipment within the facility. Consequently, the team identified numerous examples of unrestrained transient equipment that had been present at power. Potentially, the transient equipment could damage safety-related components during a seismic event. Examples found in the control room included a cart with a computer monitor and printers, wheeled print racks and a desk all located next to panels containing safety-related controls or instrumentation. Other examples outside the control room included a standing ladder located next to the battery room ventilation unit, an equipment cart and desk in the cable spreading room located adjacent to an instrument panel, and a large wheeled tool box placed next to the variable speed charging pump.

Operations management expectations regarding operability decisions were inconsistently implemented and incomplete. Occasionally, Operations management made operability decisions without consulting or informing shift supervision. Also, operability decisions were not documented because Operations management did not delineate that as an expectation. The licensee did not recognize the weaknesses until identified by the team.

AOs did not critically assess plant material conditions during their rounds partially due to the lack of management standards and expectations relative to their identifying and documenting such deficiencies. Examples of deficiencies the team found that the AOs had not identified included discolored oil and sediment in bearing lube oil sight glasses on two containment spray pumps, a missing bolt in a main steam isolation valve actuator that attached the actuator to the valve body, and multiple hanger and pipe support deficiencies.

Operations management had established guidance for log content. However, onshift personnel routinely omitted required events and information. Operations management routinely read the logs but did not correct log keeping deficiencies or reinforce the established expectations. Some of the many examples the team identified through the review of licensee corrective action reports included:

(1) In May 1993, the SS did not log plant depressurization from normal operating pressure and temperature with the reactor subcritical to 1200 psi (8,272 kPa) in response to leaking primary coolant system hot leg drain valves and a failed drain tank weld.

(2) In May 1993, the SS did not log that a hydrogen recombiner was found tagged out while the plant was maneuvered through operating modes.

(3) In November 1993, operators did not log that they ran a high and a low pressure safety injection pump without cooling water for approximately 15 minutes.

Poor log keeping had the potential for plant management to not be informed of plant conditions and operating crew performance that warranted management evaluation. Also, poor log keeping had in at least one instance prevented reconstructing a significant event sequence for post-event evaluation.

2.1.4 Repetitive Problems with Protective Tagging

There were repetitive problems with personnel protective tagging. Operators hung tags on the wrong components, prepared deficient switching and tagging orders (STO)s for the work performed, failed to perform required independent verifications, and made unauthorized changes to STOs. Contributory to these repetitive problems was the poor process established by Operations management for equipment tagging and, as observed in other aspects of facility operation, a lack of rigorous adherence by operators to procedures.

The process established by Operations management for preparing STOs was implemented by the CO1 as a collateral duty. They prepared most STOs during the midnight shift. The tagouts were usually for the succeeding day shift. Occasionally, Operations management did not provide enough details of the work to be performed. During the midnight shift, maintenance personnel most cognizant of the upcoming work activity were not present to discuss the activity or the tagging boundaries.

There were inconsistencies between the Power Control Department's tagging procedure used in the switchyard and the station's tagging procedure used in the rest of the facility. Power Control Department's tagging procedure did not include review and approval of STOs for switchyard work by control room supervisors. Thus, AOs wrote tags for the switchyard based on verbal instructions from COs without supervisory review before hanging the tags.

There were over ten examples documented in the licensee's corrective action system of significant tagging problems within the last two years. Although the potential existed for personnel injury, fortunately no workers were actually injured. Examples included:

(1) In January 1993, an operator mistakenly tagged out the over speed trip device on the wrong DG rendering both DGs inoperable for a few minutes. This resulted in the declaration of an Unusual Event.

(2) In May 1993, the STO for protective tagging on some safety injection tank motor operated valves failed to deenergize valve position indication circuits. Night shift personnel recognized the weakness while processing the tagging request, but did not aggressively pursue the issue with day shift maintenance personnel.

(3) In November 1993, an operator placed a tag on an incorrect 120 VAC breaker. During a subsequent walkdown of the tagout, a second operator and maintenance foreman failed to identify the error.

(4) In March 1994, operators prepared an incomplete STO on a main feedwater pump. Subsequently, workers found some valve actuators associated with the main feed pump pressurized because the STO failed to include the main feedwater pump lube oil subsystem.

2.1.5. Poor Support to Operations

Poor support to Operations from Engineering, Licensing, and Training caused or contributed to numerous performance problems and reduced the operator's capability to respond to operational events. Performance problems included operator errors, unnecessary burdens for onshift licensed personnel, not making appropriate NRC notifications, and diminished effectiveness of corrective action programs. Also, except in select training areas, the Operations staff either did not recognize or tolerated this ineffective support and the resulting conditions.

2.1.5.1 Engineering Support Problems

Occasionally, Engineering did not provide to Operations correct operability recommendations, effective or timely solutions to design or material condition deficiencies, and well written and technically correct surveillance procedures. Also, Engineering did not always communicate to Operations safety insights from the Palisades Individual Plant Examination for power operation or inform Operations when emergency operating procedure revisions were needed.

2.1.5.2 Training Support Problems

Select areas of licensed operator training were poor or ineffective. Also, training for some duties not strictly covered by the licensed program were poor. Problem areas were as follows:

(1) Supervisory training and coaching for Operations supervisors was limited, which contributed to poor supervisory oversight and direction.

(2) During the 1993 refueling outage, individuals qualified to operate the SFHM did not receive formal proficiency evaluations prior to handling fuel. Also, the operators received limited insights into the special physical limitations associated with the spent fuel pool. This contributed to operators trying to insert a spent fuel bundle into the wrong portion of the lead-in funnel, tangling the camera in the mast, hitting the lifting bail of the spent fuel pool tilt pit gate with the machine's service platform, and twice hitting an inspection table resting on the storage racks with the mast.

(3) Before September 1993, training in operating the reactor within allowable pressure and temperature operating regions was ineffective, contributing to several plant overcooling events. When interviewed by the team, operators who had been involved in these events indicated that they had been unsure of how to properly monitor and trend PCS cooldown. Also, operators had been unsure of the minimum allowable reactor pressure vessel temperature while the head was tensioned.

(4) Onshift Operations supervision received limited root cause and event investigation training even though they investigated the majority of the operational deviation reports. This contributed to the recurrence of performance problems and operational events.

(5) Operators received limited training and written guidance on NRC notification requirements, which contributed to operators not recognizing events that should be reported to the NRC. Examples of events not reported or not reported within appropriate time frames included exceeding the pressurizer level input to the transient and accident analysis and (as discussed in a recent NRC inspection report) inadvertent operator initiation of a containment spray pump.

2.1.5.3 Licensing Support Problems

Licensing provided poor support to Operations in the areas of technical guidance and NRC reporting. Due to omissions, inconsistencies, and the lack of detail identified over the years in the original TS, the licensee developed supplementary technical guidance to ensure operators acted consistently when various situations occurred. The combination of customized TS and the supplementary technical guidance was complex and occasionally made conservative operating decisions by operators more difficult. Also, the combined technical guidance was occasionally incomplete. Consequently:

(1) As discussed in a recent licensee corrective action report, operators were permitted to supply power to an essential inverter from the bypass regulator without considering themselves in an 8 hour TS action statement. Also, more than one inverter could be simultaneously supplied power from the bypass regulator without shutting down the reactor.

(2) Onshift supervision initially entered a TS action statement applicable to a single inoperable emergency core cooling component when operators found a cracked valve body associated with containment sump piping in February 1994. However, this condition was outside a specific TS action statement, making the general action statement for facility shutdown applicable.

(3) As discussed in a NRC inspection report, operators did not start the companion DG for 12 hours when the other DG was found inoperable in August 1992.

Although plant and Operations management were aware of the problem with the TS as well as the impact on operators, they did not take aggressive action to fully resolve the problem. The current resources committed by the licensee to improving the TS were minimal. Licensing management only assigned one person to the improvement effort and his collateral duties only allowed half his time to be spent on improving the TS.

Also, due to the limited knowledge of NRC reporting requirements and guidance, Operations relied to a significant extent on recommendations from Licensing. These recommendations were occasionally nonconservative. For example, the team identified that the NRC was not notified when reactor vessel temperature dropped below the minimum design requirement in May 1993 and when the condensate storage tank temperature increased above the maximum assumed in the transient and accident analysis in October 1992.

2.1.6 Weak Operations Self Assessment and Corrective Action

Operations self assessments as well as corrective actions to problems identified by these self assessments were weak. Contributing causes included (1) limited training of Operations staff in event evaluations and root cause analysis, (2) the lack of independent reviewers for the problem (onshift supervisors originally involved in the problem generally dispositioned corrective action system reports as a collateral duty), (3) the failure to use multiple disciplines or departments on complex problems and events, (4) operators not understanding the threshold between the plant-wide corrective action system and the lower level Operations Department's Operations Information Report (OIR) system, and (5) the lack of necessary resources and feedback mechanisms to effectively support the OIR program. Examples of these weaknesses included:

(1) The evaluation of an excessive cooldown event in May 1993 failed to identify and obtain an engineering evaluation of the long term effects on reactor vessel integrity.

(2) The evaluation of a 6000 gallon (22,710 liter) radioactive water spill in May 1993 did not recognize that personnel used an unapproved procedure and made an unapproved plant modification.

(3) Numerous deficiency reports documented longstanding problems with the station protective tagging process. However, Operations did not review these tagging problems as a broad issue, did not identify common root causes, and did not take comprehensive corrective action until February 1994 across numerous events.

(4) Operators documented some events in the OIR system that should have been documented in the plant wide corrective action system. Therefore, these events received a less rigorous review, were not communicated outside of Operations, were not captured in the site's corrective action trending program, and corrective action completion was not confirmed. Examples of improperly documented events included the failure to align seal cooling to a charging pump, failure to channel check pressurizer level instruments during a shiftly surveillance, and the failure to enter the appropriate TS action statement when both hydrogen monitors were inoperable.

(5) Consecutive audits by Operations of safety tagouts in 1993 identified repetitive omissions of numerous independent valve and breaker position verifications, indicating the lack of effective corrective actions.

(6) The team identified that as of March 1994, 40% of the 1993 OIRs needed to be dispositioned. One Operations supervisor, the OIR program originator, dispositioned the OIRs as a collateral duty. This individual, who had been transferred to the Nuclear Performance Assessment Department in February 1994, was still trying to disposition the 1993 OIRs because Operations management had not appointed a new person. Also, the dispositioned OIRs were not readily available for review by plant operators to allow them to improve their performance and sensitize them to the kinds of problems being identified.

2.1.7 Operations and Training Positive Observations

Positive aspects of operations included licensee management recognizing that performance needed to improve. Before the team arrived, the licensee took corrective actions in some poor performance areas. The licensee .mproved fuel handling performance in the spent fuel pool by selecting the most proficient operators, performing daily pre-job and post-job briefings and performing weekly proficiency familiarization with the handling machine. Operators were retrained in operating the reactor within allowable pressure and temperature operating regions. The team confirmed through observations and interviews that these corrective actions were effective. Other positive observations included formal pre-job briefings, comprehensive periodic fire brigade training, daily reports to senior corporate management on equipment deficiencies of the highest concern to Operations management, and easily accessible information to operators on the status of equipment deficiencies and the trending of system parameters.

2.2 MAINTENANCE AND TESTING

Significant weaknesses were identified in many attributes of maintenance and testing activities. Some component tests were determined to be acceptable by the licensee even though the acceptance criteria were not met or did not agree with the Technical Specifications (TS). Pump and valve testing weaknesses were caused in part by weak or missing design basis information and programmatic shortcomings. Weak maintenance practices were caused by the lack of management or supervisory oversight and clearly communicated performance expectations. Weak procedures and procedural adherence, coupled with ineffective engineering support, resulted in work implementation deficiencies, and material deficiencies not being identified or documented. Also, lack of management attention resulted in poor warehouse control of safety-related material. The preventive maintenance (PM) program was poorly controlled and implemented, resulting in some instances where equipment failures or degradation were not detected or prevented. Poor work order (WO) processing caused some delays in fixing safety-related equipment and increased backlogs.

A positive observation included detailed documentation of work performed in WO packages.

The team evaluated maintenance and testing activities by observing tests, reviewing documents, and interviewing members of the Maintenance, Engineering and Operations Departments. Detailed walkdowns of the diesel generator (DG) and auxiliary feedwater (AFW) systems were performed.

2.2.1 Some Component Testing Was Weak

Weaknesses were noted in the licensee's testing program for demonstrating equipment operability. For example, some acceptance criteria in test procedures did not agree with the Technical Specifications (TS), poor root cause evaluations were performed for some test failures, and there were questionable testing practices. The licensee did not demand strict procedural compliance. Those weaknesses resulted in questionable operability determinations and a failure to identify potentially degraded equipment. For example:

(1) The licensee's lack of understanding regarding DG starting circuitry resulted in a failure to meet the monthly testing requirements of TS 4.7.1 and potential undetected mechanical and electrical component faults. Monthly DG start tests alternated by using air start motor "A," "B," and "both." This process resulted in testing each air start motor individually once each quarter rather than monthly as stated in the TS. Inherent design differences not only existed between the A and B starting circuitry, but also between DGs 1-1 and 1-2. Consequently, given the existing test schedule, latent component faults could have gone undetected for three months. In addition, the licensee did not always follow this testing interval, in that DG 1-2 failed to start within 9.5 seconds on April 18, 1993, using the "A" air start motor, but was declared operable and not retested until October 5, 1993, (another failed start test). When the DG start time did not meet the TS

acceptance criteria, the DG air motor was declared to be in a degraded condition rather than inoperable, which was not consistent with the TS.

(2) Root cause evaluations performed by Maintenance and Engineering for slow DG start times were superficial. Following the April 18, 1993, air start motor "A" failure, an evaluation concluded that the "A" air start motor should be replaced (the same motor was previously replaced in 1992). This conclusion was based on start time performance data only and did not consider other potential causes for the slow start such as air system cleanliness, moisture content of the air, incorrect motor inlet air pressures, or response times of other mechanical and electrical system components. During observation of a March 1994 dual air start motor DG start test, the team identified that the amount of air consumed by the "A" and "B" air motors varied, and air receiver blowdown was not required to be recorded in the test procedure. In addition, upon examination of the old air motors by Maintenance, no motor deficiencies were discovered.

(3) Weaknesses identified by the team during a monthly test of DG 1-1 included: (a) preconditioning of DG 1-1 which included cranking the engine over twice for 5 seconds prior to the start of the test, without acquiring relief from the TS, or waiting for a period of time after cranking to ensure the diesel is not preconditioned, (b) over-ranging of a pressure gauge used for determining the differential pressure (dp) across the lube oil strainer on the DG engine [e.g., instrument range was 0 to 100 psi (689 kilopascal), while the extrapolated reading was ~103 psi (710 kilopascal)], and (c) no acceptance criterion for the dp across the lube oil strainer.

(4) During a review of a containment air cooler (CAC) performance test T-318, questionable testing practices were identified. Three tests were performed in February and March 1992 in which instances of excessive flow to CACs were identified (i.e., two service water pumps providing flow to one CAC) and temperature and dp instruments were over-ranged. Troubleshooting performed by an Instrumentation and Control (I&C) technician determined the cause of the over-ranged instruments was poor tubing configuration. In addition, the test procedure was revised to reduce the excessive service water pump flow. Notwithstanding these test indications, the licensee did not issue a DR or formally evaluate whether the maximum design flow rate was exceeded or potential damage done to the CACs because of overpressure. It was also unclear in the WO which CACs were actually tested when reviewing valve lineups. Because of the poor material condition of the CACs (i.e., they were leaking during the evaluation), and the significant history of ineffective repairs, the licensee planned to replace them during the 1995 refueling outage.

2.2.2 Pump and Valve Testing Weaknesses

The testing of pumps and valves was weak in numerous areas. Weaknesses were identified in the testing of some pumps and valves under the inservice testing

(IST) program required by Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (Section XI). Some pump flow parameters and results were not confirmed to be acceptable because of potentially inaccurate standards or reference values. Many IST vibration measurements were substantially lower than predictive maintenance vibration measurements which were not reconciled by Engineering. The licensee had not clearly documented the relationship between the safety analysis and the stroke time values for many motor-operated valves (MOVs) and air-operated valves (AOVs). Highly varying stroke times were recorded for some MOVs without establishing probable causes, although the valves did not reach the alert range. There was no coordination of AOV testing and its scope was limited. Relief valve testing data was incomplete or could not be recovered. Some weaknesses were identified in the IST of safety-related check valves and in the Check Valve Program including valves that were not tested. Some leak rate testing of IST category "A" valves was not performed, such as the block valves for the power operated relief valves, containment spray (CS) discharge check valves, and high pressure injection subcooling valves. Several manual valves that were relied on in Emergency Operating Procedures (EOPs) were not tested to verify that they would function. In response to the team's concerns, the licensee initiated an IST performance enhancement plan to address identified weaknesses.

2.2.2.1 Acceptability of Some Inservice Pump Test Parameters and Results Not Confirmed

Some IST pump flow testing parameters and results were not confirmed to be acceptable because of potentially inaccurate standards or reference values. Several discrepancies, which the licensee had not reconciled, also existed between vibration readings recorded during IST and predictive maintenance data. Examples included:

(1) Inservice testing of component cooling water (CCW) pumps (P-52A, B and C) during testing of one-pump or combined two-pump tests (QO-15) were judged to be acceptable by the licensee by comparing dp values across the CCW heat exchangers and relating them to CCW flow rates from curves developed in 1988 from a special CCW test (T-213). By using CCW heat exchanger dp to establish operability of the CCW pump, the licensee may not be able to clearly determine CCW pump degradation because of the interaction of additional variables that must be considered, such as CCW heat exchanger degradation. Test T-213 was developed using one-pump operation. A two-pump test, similar to T-213 to relate dp and CCW pump flow was never performed. However, the licensee utilized T-213 test results to determine flow results for the two-pump scenario. The licensee was unclear how the relationship between the T-213 test and the two-pump flow test was established and was evaluating this concern as part of corrective action. In December 1993, however, the licensee issued a deficiency report (DR) which identified two deficiencies in test T-213 questioning the licensee's methodology to satisfy Section XI Code requirements. For example (a) the flow vs. differential pressure plot for the CCW heat exchanger used in the analysis did not conform to the anticipated parabolic shape, and (b) there was no verification that the CCW inlet valves to the CCW heat exchangers were fully open when

performing the test. Because the valves were located inside the pressure taps for measurement of heat exchanger differential pressure, flow and dp values would be affected. Consequently, if the valves were in a throttled position, the resulting flow indication would be in error. The licensee performed an interim evaluation which showed that the pump would be able to achieve its design function as a basis for their action date to correct T-213 testing deficiencies by December 1994.

In addition, the team identified several other concerns regarding QO-15 test procedure adequacy, implementation and Section XI trending data. The test did not specify an acceptance range for pump discharge pressure, pump differential pressure, pump flow, or motor amperage. The test data showed flow values (using instrumentation which the licensee concluded produced erroneous results) over the last two years that were considerably less than the pump reference values. However, the licensee appropriately relied on the dp readings across the CCW heat exchangers as an indication alid test results. The licensee indicated that the flow instrumentat eadings were being evaluated.

(2) The was an apparent lack of coupling between the service water pump flow rates and required system performance which was first identified by the licensee in 1990 and later documented in a DR in 1993. The discrepancy was being evaluated by the licensee. In addition, IST pump flow test results could indicate that a pump was "operable" from a Section XI perspective (within a set range of the reference flow value), but be "inoperable" from a TS or design basis perspective if the operable range defined in IST were to fall below minimum TS requirements for a chosen reference value. This condition was a potential concern for the low pressure safety injection (LPSI) pumps (tested at approximately 6 percent of design flow), and the CS pumps (tested at approximately 10 percent of design flow).

(3) Inconsistencies existed between the pump vibration results of the IST program and the predictive maintenance program. Current IST vibration readings for several pumps were substantially lower than those measured in the predictive maintenance program. Examples included charging pump P-55C [0.31 vs. 0.43 inches per second (ips) (0.79 vs. 1.09 centimeters per second)], CS pump P-54A [0.255 vs. 0.35 ips (0.65 vs. 0.89 centimeters per second)], CS pump P-54B [0.286 vs. 0.43 ips (0.73 vs. 1.09 centimeters per second)] and CS pump P-54C [0.268 vs. 0.35 ips (0.68 vs. 0.89 centimeters per second)]. These test result inconsistencies had not been evaluated and reconciled by Engineering during the evaluation, indicting a lack of a questioning attitude and communication within the engineering groups. It was later determined that analysis methods used by the predictive maintenance engineers differed from those of the IST engineers. The latest predictive maintenance vibration summary report revealed that several safety-related pump/driver vibration readings were higher than the procedure acceptance criterion. However, corrective action was not planned or taken by the licensee. Conversely, the licensee had recommended motor replacement for 2 nonsafety-related pumps having vibration readings

below those of the safety-related pumps [0.32 and 0.35 ips (0.81 and 0.89 centimeters per second)]

2.2.2.2 Motor-Operated Valve Inservice Testing Weaknesses

The team identified several weaknesses in the IST program for MOVs. As a result of the team's concerns, the licensee indicated that a performance enhancement plan would address the findings. Weaknesses included:

(1) Engineering did not effectively pursue the root cause(s) (not specifically required by Section XI, but a good practice) of many MOVs which experienced highly varying stroke times for several months, although the valves did not reach the alert range. The valves were placed on increased frequency testing when the variations were noticed. Examples included the HPSI hot leg isolation valves (MO-3082 and MO-3083) and the pressurizer relief isolation valves (MO-1042A and MO-1043A). Eventually the stroke time trends stabilized without the need to perform repairs and the testing frequency was changed to quarterly.

(2) The IST group was unaware of a modification which changed operator gear ratios on some HPSI MOVs (MO-3062, MO-3064, MO-3066, and MO-3068) in June 1993. The modification changed the stroke times. The IST group first suspected that something was wrong with the valves (because of stroke time changes) and increased the surveillance frequency. The fact that a modification had been performed was not discovered by the IST group until December 1993 (six months after the modification was implemented). Poor implementation of the modification process resulted in the IST group not knowing of the engineering change, and of the requirement to perform new reference stroke times as required by Section XI. No DR was written, even though this occurrence indicated a potential Engineering-IST interface weakness.

(3) The licensee indicated that there was not a defined and clearly documented relationship between the safety analyses and the valve stroke times. All reference values had been established as the mean stroke time for each valve. During the evaluation, the licensee indicated that the acceptance criteria used in the tests were bounded by assumptions made in the safety analyses. A more indepth study was to be completed by January 1995. In addition, stroke times achieved were within indicated design allowables.

(4) The MOV trending database was incomplete and not integrated. Engineering could not easily determine from the trending data when a recorded stroke time was performed to document a new reference test or when increased testing had been performed. Trend data also did not indicate whether the alert or action ranges had been exceeded. The licensee had planned to update their data management capabilities for IST parameters.

2.2.2.3 Air-Operated Valve Testing Weaknesses

The licensee did not have a coordinated plan for the maintenance and testing of AOVs. The licensee had accumulated some information over the last two years on AOVs prior to issuing an AOV Program Plan on March 22, 1994. Some of the milestones yet to be performed under this plan included identification of the scope of work to support the Maintenance Rule in the AOV area, performance of walkdowns to collect name plate and material data, verification that design documents matched installed equipment, review of maintenance history to determine performance problems, and the development of preventive maintenance (PM) activities for each valve group. Completion dates for the milestones ranged from December 1994 through April 1998. Several of these milestones have the potential to initiate new or revised AOV testing and maintenance requirements.

When questioned by the team, the licensee had difficulty in determining the total number of AOVs installed, including the number that were classified as safety-related and the number of those included in the IST program. The design of the plant relied heavily upon AOVs in that there were 1030 installed AOVs of which 315 were safety-related. Approximately 180 AOVs were in the IST program. For those AOVs that were tested in the IST program, the licensee indicated that there was not a defined and clearly documented relationship between the safety analyses and AOV stroke times. All reference stroke time values had been established as the average or mean stroke time for each valve. As a result, a discrepancy was identified by the licensee between the safety analysis value for the maximum closure time of the main feedwater regulating valves (CV-0701 and CV-0703) (20.5 seconds) and the acceptance criterion in the test procedure (24 seconds). The licensee wrote a DR to assess the concern. However, actual stroke times were less than the maximum allowed in the safety analysis.

2.2.2.4 Incomplete Relief Valve Testing Data

The team noted that extensive information regarding relief valve design and testing was developed by the licensee in 1992. However, the licensee was unable to recover this data for its own use or the team's review. As a result, the licensee did not have a basis to ensure that safety-related relief valves were properly set, maintained and tested. Some relief valve setpoint information was contained in PM documents, although the accuracy of that information was not verified by the team. Lack of this information, or inaccurate information, could cause future implementation problems as the licensee conforms to the broader requirements of the 1989 ASME Code that was scheduled to be adopted prior to the 1995 refueling outage.

2.2.2.5 Instances of Check Valve Testing and Maintenance Scope Weaknesses

In the IST area, the team identified an instance where the licensee failed to test at full-flow conditions, check valves CVC2138 and CVC2139, which were located in the flow path from the boric acid injection to charging pump suction. There was an incorrect reference to a boric acid pump IST (QO-18) which indicated that full-flow testing of the check valves was performed as required by Section XI. The IST procedure for the check valves was revised and implemented in May 1994. The incorrect reference in the IST program resulted in the IST group not verifying that the valves were tested. The licensee developed, as part of its performance enhancement plan, an action to review test procedures to ensure that check valves were adequately tested. There was also an ongoing effort by the licensee as a result of an earlier NRC inspection to verify that all check valves were appropriately tested.

The Check Valve Program focussed primarily on disassembly and inspection requirements for safety-related and nonsafety-related check valves. In April 1994, the licensee identified several problems with check valves in the reactor cavity drain lines and in the AFW and DG rooms. The valves were shown on drawings, but none had equipment ID numbers, or were included in the Check Valve Program. Debris prevented full seating of valves in reactor cavity drain lines which could have prevented the reactor vessel cavity from being flooded as required by design to provide external cooling to the reactor vessel during operation of the CS system. No PM or testing had been done on these valves to ensure their continued reliability or to verify that they would function as designed. The licensee also identified that the DG floor drain check valves were not previously tested, and may also not prevent back flow into the rooms. The licensee was evaluating potential repair or replacement options that would be implemented during its 1995 refueling outage for the DG valves.

2.2.2.6 Many Important Manual Valves Not Periodically Tested

Seventeen manual valves that were relied on in EOPs were not tested to verify they would function. As an example, the team found that the manual bypass valve for the steam flow regulating valve to the P-8B AFW pump turbine had not been tested. The licensee subsequently cycled the bypass valve, however, the valve was never tested to verify that it could perform the function mentioned in the EOP, which included manually regulating the steam flow to the AFW pump turbine in the event that the main valves closed on loss of air to their actuators. The licensee subsequently performed a search which discovered an additional 16 manual valves installed in various systems that were relied upon for operation in EOPs that were also not tested. The licensee was evaluating appropriate corrective action at the close of the evaluation.

2.2.3 Weak Maintenance Work Practices

Oversight of maintenance activities by supervisors and managers through observing in-process work was consistently low. This contributed to procedural adherence problems by personnel performing maintenance activities and a failure to acquire engineering assistance to evaluate problems in some instances. In addition, poor support from Engineering contributed to inadequate maintenance work procedures and poor root cause evaluations. These weaknesses resulted in instances of questionable equipment operability, damaged or degraded equipment, and equipment rework.

(1) Poor procedures and work reviews resulted in an unapproved pump modification which permanently installed alignment plates and adjusting bolts on multiple safety and nonsafety-related pumps. Many of the

alignment adjusting bolts remained in full contact with the pumps, creating the potential to cause excessive stresses on the pump casing, misalignment of the pump drive shaft and abnormal journal bearing wear. Alignment procedures did not caution maintenance workers to back off on the bolts once an alignment was completed. As a result of the team's concern, the licensee initiated a DR to assess the as-found condition of all pumps on site and implemented corrective action on 16 pumps. In addition, the procedure for performing pump alignments was also revised. The licensee stated that no pumps were overstressed, but that three pumps were affected (i.e., showed movement when the adjusting bolts were relaxed).

(2) While completing a WO to adjust the stroke of a main feedwater regulating valve on March 24, 1994, I&C craft completed the calibration sheet inaccurately. The team noted several weaknesses and poor practices in calibration sheet accuracy and control of design basis information, technician understanding of and management guidance on calibration sheet "control action" sections, appropriate questioning attitudes among maintenance personnel, and adequacy of administrative reviews. In addition, the licensee's review identified calibration sheet inconsistencies and inaccuracies, significant weaknesses in procedural guidance for their use and control, and poor communication of standards and expectations.

(3) In February 1993, during repair of #3 cylinder for the variable speed charging pump (P-55A), several broken parts were found throughout the system, but a thorough search and complete parts inventory was not conducted. Subsequently, during post-maintenance testing, the pump failed to meet flow requirements because a piece of packing and part of a broken spring were jammed between the pump suction valves and valve seats. In addition, a comprehensive root cause analysis of the pump failure could not be performed by Engineering, because a complete parts inventory, including critical measurements of worn and damaged pump components, was not taken.

(4) The AFW alternate steam supply valve (CV-0521) was sometimes rapped with a 3-pound hammer (determined as an acceptable practice by a system engineer) to help it move to the open position when its disk became stuck in its seat. This occurred when the valve was found to be stuck in its seat during surveillance testing. The valve was not declared inoperable when the disk became stuck and subsequently loosened by using the hammer. A chronic history of the disk sticking in its seat and not being able to close under design flow prompted Engineering to modify the valve operation.

(5) The DG 1-1 engine-driven fuel oil (FO) pump was replaced without using the design-required alignment dowels due, in part, to not requesting engineering support. Following the FO pump failure in April 1993, maintenance workers observed that the original pump was missing one of two alignment dowels. In addition, because of excessive misalignment between the replacement pump and the dowel pins, the pump was installed without dowels. This action required that the installation process and

configuration be modified, neither of which occurred. Also, a safety evaluation was not performed to evaluate long-term consequences of eliminating the alignment dowels and the potential for misalignment to occur. As a result of the team's concern, a DR was written and a 50.59 was performed which assessed the modification of the FO pump as acceptable.

(6) Maintenance did not adequately troubleshoot and plan repair activities for a level control valve (CV-0605) for high pressure feedwater heaters. While the team was on site, the repair to CV-0605 demonstrated a cumbersome and untimely process in identifying the causes of misalignment, completing actual repairs, and reassembling the valve. Only after the fifth reassembly (including one with a test stem) did the valve stroke without binding or galling the stem. In addition, the licensee had just begun to address the root cause of excessive maintenance over a period of 13 years on this valve and a companion valve (CV-0601). The valves had experienced chronic excessive wear, which the licensee attributed to the proximity of the valves to a tee (CV-0605) and an elbow (CV-0601). The licensee replaced valve internals six times on CV-0605 and five times on CV-0601 since 1981.

2.2.4 Some Material Condition Deficiencies Not Identified and Documented

Several material deficiencies existed due, in part, to not communicating performance standards and expectations. The licensee did not fully implement work processes, the corrective action program, and the Maintenance policy guidance requiring area walkdowns. Team walkdowns revealed many deficiencies, most of which were subsequently documented on DRs, evaluated for equipment and system operability and corrected. Examples included the following:

(1) The color of the bearing sight glass oil was significantly darker than the oil in the bubbler for containment spray pump motors (P-54A and P-54B). An analysis of oil in P-54A indicated that wear metal, dirt, rust and large chunks of plastic/teflon were present. The oil sample for P-54B was not taken from the correct location, causing the analyzed sample to be unrepresentative of the oil observed to be discolored. This sampling method was typical of other pump motor oil samples taken on site. During previous oil analyses, when contaminants reached a "caution" level, a DR was not generated, and corrective action performed was limited to changing the oil rather than examining the pump bearing for damage. Failure to perform a proper PM for the motor bearing oil resulted in the licensee declaring the P-54A pump inoperable. In addition, the licensee issued a DR to revise the PM activity for performing the oil analysis PMs on all associated motors on site.

(2) There were multiple hanger deficiencies including loose or missing hanger fasteners, loose base plate bolts, cracks in a wall caused by embedded support bolts, and missing fasteners on large structural supports in the CCW room. The latter deficiency affected portions of the main steam, atmospheric dump valve, and AFW piping systems.

(3) There were several hardware deficiencies on DGs 1-1 and 1-2 such as insufficient fastener engagement on the air intake silencers, missing or loose fasteners and broken brackets connected to the jacket cooling water lines and the DG exhaust shroud, and a leaking DG exhaust manifold.

(4) Some spring can hanger supports were loose, did not have cold and hot settings marked on the can, or appeared improperly set.

(5) Main steam isolation valves were missing actuator support fasteners, presumed by the licensee to have not been reinstalled after completing a modification several years ago.

(6) An AFW pump was missing a support bracket for the bearing cooling water line.

(7) Vendor reports regarding degraded material condition concerns for the DGs and AFW turbine driver were not formally documented and evaluated. The Vendor Information Program did not ensure that updated vendor information was routinely requested, evaluated, or incorporated into maintenance activities.

The licensee indicated that some of the above deficiencies existed for several years. Failure of the licensee to identify the deficiencies resulted in inoperable equipment, degraded equipment and rework.

2.2.5 Poorly Controlled Warehouse Storage of Safety-Related Material

Numerous fundamental weaknesses were identified regarding material control and supply of parts from the warehouse because of a lack of adequate management oversight of the warehouse facility. These weaknesses, if uncorrected, had the potential to degrade installed equipment or cause early equipment failure. Team walkdowns revealed many concerns, most of which were subsequently documented on DRs. For example, the licensee did not:

(1) properly segregate and secure safety-related, nonsafety-related, and nonconforming items, including clearly identifying the latter items.

(2) dispose of components at the end of their shelf life, did not specify shelf life of certain components, and did not perform engineering evaluations to extend the shelf life of other components.

(3) correctly store components in the warehouse, including allowing protective packaging to be breached and inappropriately protecting components to ensure foreign material was excluded.

(4) properly control material control tags prior to use or when material was returned to the warehouse.

Three different computer databases and a hard copy manual process were used to access requested information regarding stocked items, purchase order items, and shelf life concerns. Inaccuracies were also noted between actual stock inventories and database information.

In addition, replacement part unavailabilities resulted in several temporary modifications remaining installed for extended periods, and WO planning delays.

2.2.6 Poor Support for Preventive Maintenance Impacted Equipment Performance

Poor support for PM activities was evidenced by identified equipment problems and lack of control of the licensee's program. Resulting equipment problems were safety significant because they had they potential to prevent components from performing their safety functions. The licensee's program lacked the rigor needed to prevent future similar problems. Several failures or degraded conditions, a number of them recently identified, occurred because PM was not performed on the equipment or the PM performed was ineffective. Most of the following examples were identified by the team during walkdowns, and through Licensee Event Report and DR reviews:

(1) Reactor cavity drain check valves (having no PM) were found clogged with debris causing them to be declared inoperable.

(2) A CS pump was found with contaminated oil and was declared inoperable.

(3) A charging pump experienced a catastrophic failure in 1993 after a PM (which was originally issued to prevent a repeat failure of an earlier similar occurrence) was eliminated in 1990.

(4) Inverter transformers were imbalanced because of reduced voltages and lack of PM. Licensee tests of the inverters in 1994 indicated that they could perform adequately provided their associated transformers were kept balanced through periodic maintenance.

(5) Three of four inverters were operating with insulation that had exceeded its specified life by several years.

(6) DG air receiver blowdown valves were found clogged with scaling.

(7) A General Electric model SMB hand switch failed because of oxide buildup which led to identification of six Class 1E hand switches installed in various systems with similar accumulated oxide.

(8) An emergency escape airlock equalizing valve stuck open because of the lubricant becoming tacky and from infrequent use.

(9) Temperature controllers for the CACs were not properly calibrated and maintained.

(10) The motor bearing for a CAC air cooler was being allowed to run to failure (according to work package documentation) rather than performing the PM activity to grease the bearing.

The licensee's PM activities were largely controlled by the Periodic and Predetermined Activity Control (PPAC) program which experienced significant weaknesses because of insufficient management support including: (1) about one-third of the PM activities were not formally controlled within the PPAC program, which included approximately 50 percent of "Q-List" components, (2) certain PPAC PMs which were not performed while their deletion was pending, (3) many I&C PPAC PMs which did not have an established interval, (4) PPAC PMs which were deferred and deleted without system engineer and Operations concurrence, (5) PPAC PMs which were not accomplished on schedule, resulting in regular reliance on performing the PPAC PM within the 25% grace period, (6) vendor information which was not routinely incorporated, and (7) the lack of management reporting of PM status. The licensee had not evaluated the need for periodic pump disassembly and inspection, and had not included several DG support system components in its PM program.

The licensee conducted a PPAC Upgrade Project from October 1992 through April 1993 which resulted in extensive deletion or extension of the periodicity of many PMs, but virtually no addition of PMs. While most were deleted or extended appropriately, some did not have sufficient supporting information. Examples included those extending intervals for safety-related instrument calibrations. fan motor refurbishment and for the rebuilding of feedwater system solenoid valves.

2.2.7 Weak Maintenance Work Order Tracking And Reporting

The licensee's work control process exhibited weaknesses in tracking and reporting. In some instances, these weaknesses were caused by undefined or poorly defined program elements and unclear procedure guidance. Examples included:

(1) Some work requests were not entered into the Advanced Maintenance Management System (AMMS) in a timely manner as required. Among others, a group of 28 work requests (25 were Q-listed), pertaining to thermal overload settings for breakers for various equipment was initiated on April 15, 1993 but was still not entered into AMMS when the team was on site, because of organizational confusion within the engineering groups regarding which group had responsibility and what action was appropriate. The affected equipment included a diesel fuel oil transfer pump, the entire alternate safe shutdown panel, the recirculation fan for the cable spreading room, and the high current alarm status for seven HPSI MOVs. The latter would not alert operators to take necessary action to prevent HPSI valve motor failures under excessive current conditions.

(2) More than two-thirds of the WO backlog (approximately 1650) were not ready to be worked. Until requested by the team, the licensee had not made an overall safety/reliability assessment of the maintenance

backlog. The licensee was in the process of evaluating its backlog at the conclusion of the evaluation and planned to implement such an assessment on a quarterly basis.

(3) The licensee's management information system indicated that similar numbers of preventive and corrective maintenance (CM) activities were performed. However, the number of PM activities was actually lower because the licensee considered many corrective maintenance activities on degraded (but not failed) equipment as PM. This resulted in a more favorable PM-to-CM ratio than what was actually occurring.

2.2.8 Positive Observation

The Maintenance Department encouraged the craft to document ongoing repair activities in the WO package. This allowed Maintenance and Engineering to easily access material history information that would otherwise be lost. The available material history information was useful to Maintenance and Engineering in performing root cause analysis and post-job critiques.

2.3 ENGINEERING AND TECHNICAL SUPPORT

Support to the plant from both Nuclear Engineering and Construction (NECO) and Systems Engineering (collectively referred to as Engineering) was often weak. Resolution of some equipment and system problems was untimely and ineffective. There was an over-reliance on operator actions to compensate for some design conditions. Control and quality of plant modifications were sometimes deficient. Configuration control by Engineering was ineffective. The roles and responsibilities of the two onsite engineering organizations and the interfaces between them were not well defined. Authority was not clear and accountability was not maintained. Some system engineers assumed total ownership of their systems, while others exercised very little. Standards and expectations were not effectively developed and communicated.

A positive observation made by the diagnostic evaluation team (DET), was the use of dynamic computer models for evaluating electrical design issues.

The team performed in-depth evaluations of the auxiliary feedwater and diesel generator systems and their support systems, and of other significant equipment issues. The team also evaluated the effectiveness of the engineering and technical support function by reviewing routine engineering support to the plant, resolution of equipment and system problems, required operator actions, plant modifications, configuration control, and organizational issues.

2.3.1 Plant Support From Engineering Often Weak

Evaluations in support of operability determinations were untimely and of poor quality in several instances. Root cause analyses were often weak or untimely. Support was poor for development and review of procedures and instructions. Contractor control by Engineering was poor.

The licensee recognized that Engineering support needed to be improved in its self assessment in 1991. Causes of weak plant support by Engineering were historically incomplete design basis information, and a tendency to perform evaluations and institute administrative controls as corrective actions instead of correcting plant hardware deficiencies. In addition, a lack of understanding of the operability evaluation process by engineers and managers contributed to this weakness.

2.3.1.1 Evaluations in Support of Operability Determinations Untimely and of Poor Quality in Several Instances

Factors which contributed to poor engineering evaluations were a poorly defined operability process and engineers' lack of understanding of the design bases. In addition, interviews by the DET revealed that many engineering personnel had only recently become aware of their roles in determining equipment and system operability. Some engineering managers had only recently become familiar with NRC guidance on operability determinations contained in Generic Letter 91-18. There was a general weakness at all levels concerning training of engineers in evaluating degraded equipment for operability. The following are examples which demonstrate weaknesses in Engineering's evaluations.

(1) On February 10, 1994, during a walk-down of cable trays, as part of an Appendix R review, the licensee discovered that the separation barriers were missing for the reactor protection system (RPS) channels 1 and 3 for cables located in the same cable tray. UFSAR section 8.5.3.2 requires that, if channel 1 circuits are routed in the same raceways as channel 3 circuits, then the circuits must be separated by a barrier. The licensee performed an immediate operability determination and, based on an Institute of Electrical and Electronics Engineers, Incorporated (IEEE) paper on cable separation (IEEE 90 WM 254-3 EC) and other internal "engineering aid" documents, found the RPS operable. The documents included discussions on low voltage instrumentation and control (I&C) cables similar to the RPS. The licensee's evaluation indicated that, under a postulated electrical fault, the amount of heat generated in the RPS cables would not be enough to affect adjacent RPS cables not separated by a barrier.

In response to the NRC resident inspector's concern, the licensee found that the operability determination was flawed and potentially incorrect. Although the reasons cited in the IEEE document for operability of low voltage I&C cabling were correct for some situations, the IEEE document did not apply to adjacent cables under an electrical fault. The licensee initiated an engineering evaluation, but terminated this evaluation upon finding that it would not resolve the issue and instead performed a modification to put a barrier between the cables. Had these circuits failed (short circuit), there was a potential that the RPS would not trip upon demand to shut the reactor down.

(2) Operability evaluations of the DG fuel oil transfer system performed in October of 1993 and, while the team was onsite in April of 1994, were untimely and of poor quality. Several DG fuel oil transfer system design weaknesses and degraded conditions that were addressed by the evaluations had not been resolved and operability issues remained during the DE.

During the onsite evaluation, the licensee discovered that the DG fuel oil transfer system was supposed to be safety-related and seismically-qualified. These discoveries occurred while the licensee was continuing its investigation and evaluation of its use of non-conservative DG fuel oil consumption rates, an issue raised by the 1991 Regional Electrical Distribution System Functional Inspection (EDSFI) team and the licensee's DG Design Basis Documentation (DBD) effort. In addition, the licensee had been aware since 1986 that it did not meet the 27.6 hour run time using only the contents of the day tank, as stated in the UFSAR and TS bases. There was no operability evaluation on the DG fuel oil system until the evaluation in October 1993. The October 1993 evaluation was performed after the licensee determined in August/September of 1993 that the DG fuel consumption rates had changed significantly from those previously assumed in the TS bases and UFSAR (27.6 hours to 11.2 hours). Using engineering judgement, the licensee concluded that 11.2 hours provided adequate time to get a tanker truck onsite to refill the day tank. However, the evaluation did not address that 1) filling of the day tanks from a tanker truck had never been demonstrated, 2) the bounding worst case calculation in the UFSAR and TS bases (27.6 hours) was significantly exceeded and created the potential for an unreviewed safety question (USQ), and 3) the conclusions reached by the NRC's Systematic Evaluation Program (SEP) in 1981 on the adequacy of the design of the fuel oil system (based on 27.6 hours) might no longer be valid. During all of these evaluations, the licensee concluded that the system met the design basis.

During the DE, operability determinations were written to support continuing DG operability based on the licensee's April 1994 finding that the DG fuel oil system did not meet GDC 2 for tornado protection. However, these evaluations did not recognize that, although the T-10 storage tank had been declared inoperable, 1) the fuel oil transfer system was not seismically qualified or protected from seiches, 2) the electrical power supplies were not separated or seismically qualified, 3) the modification history and effects of maintaining and treating a safety-related system as non-Q for over 19 years was unevaluated, and 4) filling of the day tanks from a tanker truck still had not been demonstrated. An unqualified DG fuel oil transfer system would increase the potential for a loss of fuel oil supply to the DGs while they were operating in response to a loss of offsite power. At the end of the DE, the licensee submitted a justification for continued operation (JCO) to the NRC staff and was investigating possible corrective actions for the fuel oil transfer system.

(3) The DET found that the design of the DG dual air start circuits, that were intended to be redundant on each DG, made the DGs susceptible to loss of automatic start capability of both DGs following certain single failures when the "A" start circuit of either one of the DGs was already degraded (unable to perform its design function). Since Systems Engineering did not understand this susceptibility, they did not recommend that the DG should have been declared inoperable when the "A" start circuit was degraded or inoperable. The air start circuit for the DGs was unusual in that: a) The DGs were not automatically started on an accident signal. Instead, they were started only on an undervoltage of a 2400 VAC safety-related bus, and b) undervoltage on a 2400 VAC bus provided a start command to the "A" start circuit for that bus' DG and a start command to the "B" start circuit for the opposite bus' DG. These two design features resulted in the above susceptibility to a single failure if the "A" start motor on either DG was degraded, with single failures as noted below.

A configuration persisted for several months just prior to the DE wherein an "A" air start motor was degraded (unable to perform to the response time required by the accident analysis), yet the licensee determined that the emergency power system, including both DGs, continued to be operable. One example of a single failure and one example of a maintenance condition that could result in failure of both DGs when DG 1-2 air start motor "A" was degraded was:

a) loss of battery 1 during a loss of coolant accident (LOCA); this single failure would prevent DG 1-1 from starting on either air motor and inhibit the start signal to DG 1-2 air motor "B", leaving only the degraded/failed air motor "A" to start DG 1-2.

b) a single maintenance action removing the opposite 2400 VAC bus from service under a limiting condition for operation.

(4) NECO, in late 1992, found a safety-related inverter had significant harmonic distortion on its AC output. Two safety-related chart recorders powered from the inverter were operating at twice rated speed because of the harmonic distortion. A modification was required in 1993 to reduce the distortion and eliminate the recorder overspeed. The modification permanently removed vendor supplied output capacitors. This modification was implemented without an adequate operability evaluation or adequate validation of design assumptions, engineering analysis, vendor consultation, or post-modification testing. After the DET questioned the operability of the inverter, the licensee performed an operability evaluation including special tests to further evaluate the distortion. The licensee concluded that the distortion had never been within the UFSAR and vendor limits of 5 percent and probably could not be reduced to below 9-10 percent. However, the licensee concluded this condition had not degraded equipment, prior to the special tests, except for the 2 recorders. This problem had the potential to degrade the redundant safety related instrument power supplies.

(5) Surveillance tests for LPSI pump P-67B using procedure QO-20 on January 22, 1993, and for AFW pump P-8C using procedure MO-38B on December 16, 1993 were part of the Inservice Test (IST) Program, and were tests in which the subject pumps were not run for a minimum of five minutes prior to taking data. The test procedures required this minimum run time to allow the test parameters to stabilize prior to taking data. Operations personnel did not follow the procedures regarding minimum run time and instead ran the pumps only 2 to 3 minutes. Systems Engineering, after their review of the tests, did not inform Operations of the failure of the tests to meet the above criterion and thus the failure of the tests to demonstrate operability.

2.3.1.2 Root Cause Analyses Often Weak or Untimely

Multiple repeat failures of safety-related equipment often occurred before the root cause was identified. In some cases, several attempts at corrective action were not effective because the root cause was not determined. This resulted in extra burdens on the operators and increased challenges to other equipment. A lack of training on root cause analyses and a lack of emphasis and resource allocation by management were contributing causes for weak or untimely root cause analyses. The examples below are illustrative of this performance issue.

(1) A DG operated for at least 20 months with a faulty voltage regulator. Three current fluctuation occurrences while DG testing in parallel with the grid during 1990 and 1991 were incorrectly diagnosed by Systems

Engineering. After a fourth occurrence in May 1992, the licensee identified that the root cause had been loose solder connections resulting from vibration and thermal aging of the voltage regulator which had been in service for about 22 years. There was the potential for the DG to fail upon demand, with the subsequent loss of the safety-related equipment powered from this DG.

2) The AFW alternate steam supply valve, air-operated valve (AOV) CV-0521, had been unreliable, on both opening and closing, since 1988. This valve had a design safety function for both opening and closing; opening of the valve was needed to admit steam to the turbine, while closure of the valve was required to isolate steam to the turbine and prevent pump damage if pump suction was lost. However, the valve had experienced actual failures in both opening and closing and could not reliably perform either function. The root cause of the failures to open and close was not conclusively determined when the DET was onsite. The licensee attributed the problem to an undersized air-operated valve actuator. The normal position of the valve was changed from closed to open in 1992 to help ensure this alternate AFW steam supply would be available. With the valve left in the open position, the valve could not be relied on to shut and protect the TD AFW pump in the event of loss of suction to the pump while operating on the alternate steam supply during the loss of main feedwater event.

(3) Root cause evaluations, by Systems Engineering, of the slow DG start times were poor. Following the April 18, 1993, air start motor "A" failure, an engineering 50.59 evaluation concluded that the "A" air start motor should be replaced (also replaced in 1992). This evaluation did not consider air system cleanliness, moisture content of the air, air pressures, or response times of other mechanical and electrical system components as possible contributing or root causes. Since subsequent testing of the air start motor that was replaced did not identify a failure or degradation of the motor, the root cause of the slow air start of the DG may not yet be understood and corrected, causing a potential for continuing failures in the future during tests or on demand.

2.3.1.3 Poor Support for Procedures and Instructions

Engineering support for revising the plant operating and maintenance procedures was poor. Deficient procedures and procedures that were not revised in a timely manner contributed to long-standing procedural compliance problems at Palisades. Management expectations on procedural compliance and reporting of inadequate procedures were unclear and inconsistent. Poor procedural support had the potential to result in plant transients or damaged equipment, questionable operability of equipment, and confused guidance to operators, as well as other problems. Examples were:

(1) The engineering controls for assuring that operating procedures were appropriately revised following plant modifications were weak. Certain modifications were installed and placed in service without the development of the associated operating procedures. Examples included:

Modification SC 93-054 in November 1993 on containment air cooler temperature controls and the upgrade of the vacuum degasifier level controller done under work order (WO) 24300577 in March 1994.

(2) In November, 1992, Engineering identified as part of its design basis reconstitution effort that the EOPs needed to be revised in three different areas due to concerns with the size of the cross-connect line between two tanks (T-81 and T-2) that supplied water to the AFW pump suctions. The Operations procedure sponsor for the EOPs was not notified of the need to revise the procedures until April 1994.

(3) Prior to March 1994, when a new procedure was issued, there were several questionable maintenance practices during the installation of the new turbine driver for AFW pump P-8B, partly resulting from a failure of maintenance technicians to communicate with Engineering and poor support from Engineering. Lack of a caution statement in the pump alignment procedure against cold-springing of piping resulted in the potential for overstressing the inlet piping and causing misalignment.

(4) The fuel oil transfer pump surveillance test procedure MO-7C did not verify pump operability because the procedure lacked quantitative acceptance criteria. The licensee planned to revise the procedure.

(5) The modification (SC-92-127) in mid 1993 to solve the speed and pressure oscillations of the turbine-driven AFW pump was only partially effective. Incorrect installation caused by poor installation instructions from Systems Engineering resulted in improper response of the AFW flow instrumentation under actual flow conditions. The installation instructions did not include steps to leave two sliding links in the instrument loop in the required position. The post-modification test procedure, provided by Systems Engineering, failed to detect the installation error. The technical review of the modification package, by Systems Engineering, also failed to discover the error. The error was later discovered during the performance of TS surveillance testing.

2.3.1.4 Poor Contractor Control by Engineering

There was often poor oversight over contractors' work, including ineffective technical reviews of their work products. In some instances, this resulted in plant operation outside the analyzed conditions or a significant plant transient. A lack of training for engineers on contractor control was a cause for these problems.

In January 1993, the setpoint for pressurizer level control program was changed to operate at the maximum possible level, while at power, in order to secure letdown and charging while repairing the variable speed charging pump discharge isolation valve. Conflicting information supplied to the contractor by NECO and its misapplication by the contractor resulted in incorrect modelling of pressurizer level in the loss of external load analysis. In addition, Operations incorrectly translated Engineering supplied information. As a result, the plant operated, while the valve was being repaired, with pressurizer level above that assumed in the loss of external load analysis and thus outside analyzed conditions. Subsequently, Engineering reevaluated the loss of load analysis using more accurate assumptions and concluded that the pressurizer would not have reached a solid condition and the primary coolant system (PCS) would not have overpressurized in the event of an external loss of load.

The quality of engineering support received from the contractor for the 1992 main turbine digital electro-hydraulic (DEH) control system modification (FC-844) was poor. Poor oversight of the contractor's work (e.g., review of design package) by Engineering was the primary cause of this problem. It took three events involving plant trips (LERs 92-039, 034, and 035) and three modifications (all done under FC-844) to correct the problems associated with the power supplies to the DEH computer. Another modification (SC-93-023) was required to upgrade the air conditioners for the DEH room and the cables associated with the modified power supplies. These requirements should have been recognized during the original modification. The plant trips resulted in increased challenges to safety systems.

2.3.2 Resolution of Some Equipment and System Problems Untimely and Ineffective

Many problems were identified to Engineering; however, they were often slow to evaluate them, recognize their safety significance and effectively resolve them. In some cases, even after the safety significance was recognized, Engineering was slow to act. The licensee recognized this problem and initiated a design basis documentation (DBD) program in the late 1980s to improve understanding of the design basis and thus help improve the problem resolution process. Other causes for this weakness included: management standards and expectations that were not well defined or enforced, barriers to resolving problems in the corrective action process, an ineffective prioritization process, and weak training of Engineering personnel in the operability determination process.

(1) In 1993, Engineering had identified through the AFW design basis documentation (DBD) program a concern as to whether, during accident conditions, adequate AFW would gravity flow to the AFW pump suctions from the condensate storage tank (CST) and primary makeup water tank (PMWT). This AFW flowpath concern was not evaluated until the DET questioned the lack of calculations for flow. As a result of the evaluation, the licensee declared this suction path inoperable and required resolution of this issue prior to startup.

(2) The 1991 EDSFI conducted by Region III identified 17 thermal overloads (TOLs) which were not sized in accordance with planned corrective actions determined from a 1986 coordination study. An NRC inspection found, in August 1993, all the engineered safeguards room cooler fans inoperable, resulting from improper thermal overload protection settings. This condition existed with the reactor critical during May 16 to June 5, 1993 (LER 93-008). The licensee indicated that corrective actions on all safety-related TOLs had been completed by December 17,

1993. However, in response to DET questions, the licensee found that approximately 25 Q-listed motors and breakers had not previously been tracked for corrective action and were not included in the December 17, 1993 corrective actions. Examples of these affected components were the TOLs for the cable spreading room recirculation fan motor, 7 motors for HPSI MOVs, the spent fuel pool booster pump motor and the C-150 alternate safe shutdown panel breaker. In addition, during the DE, Systems Engineering identified that the incorrectly-set TOLs for one of the above 25 Q-listed components was the safety-related DG fuel oil transfer pump P-18. Incorrectly sized thermal overloads increased the potential for the above motors to trip prematurely or, for breakers to trip that would prevent operators from receiving an alarm that would allow them to take protective actions.

(3) In September, 1992, an auxiliary operator inadvertently left the air supply valve to an AOV (CV-0880) in the service water "A" supply header to the CCW system closed for two days. The Systems Engineering evaluation failed to recognize that backup SW seal cooling to the ECCS pumps had been susceptible to a single failure that could have resulted in loss of all ECCS pumps. An NRC service water inspection team identified this issue in January of 1994 as a single failure vulnerability which could render all ECCS pumps inoperable.

(4) The primary coolant system (PCS) was cooled to below the temperature limit of 70 degrees F (21 degrees C) on two occasions with the reactor vessel (RV) head bolts fully tensioned, and the PCS cooldown rate limit was exceeded on seven occasions while going into shutdown cooling. The RV was the limiting component in these events, but no formal engineering evaluation of the cumulative effects of these transients on the RV had been performed prior to the DE. A subsequent evaluation by Engineering showed that no ASME code limits for the RV had been exceeded. Consequently, there were no cumulative effects on the ductility or integrity of the RV.

(5) In late 1992, the condensate storage tank (CST) water temperature was found to be 10 degrees F above the assumptions used for accident analyses in the UFSAR. The engineering evaluation by NECO was completed 3 months after the event and did not consider all aspects, such as the effect on the net positive suction head (NPSH) available to the AFW pumps and maximum attainable CST temperature. This event slightly increased the potential consequences of certain postulated events, including a loss of NPSH for the AFW pumps, during the time the CST temperature was elevated.

(6) Current plant operating conditions and some postulated accident scenarios were not reflected in the licensee's Individual Plant Examination (IPE). These conditions and scenarios are listed below.

- A postulated accident scenario, described in IN 89-54, "Potential Overpressurization of the CCW system" was not included in the IPE. This generic issue was initially screened by the licensee as an event that was outside of the design basis. However, questions by the team prompted the licensee to determine that this event had a significant impact on a sister plant's IPE and may have risk-significant implications to Palisades. Further review by the licensee revealed that a weak NECO evaluation had prematurely closed out this issue.

- Steam generator overfill and intersystem LOCA events were not included in the IPE. These issues were closed out for Palisades in its SER for a full term operating license by statements that they would be included in the IPE.

- Palisades' over-reliance on operator actions was not addressed. April 1994 correspondence from the staff to the licensee, regarding the assumptions used in the IPE, questioned the nonconservative manner in which industry standard human error rates were utilized. The DET identified: a relatively large number of operator actions; persistent problems with procedural adherence; and poor quality procedures. The licensee identified a lack of knowledge and understanding by the plant staff of the IPE/PRA process and its usefulness in improving plant safety as contributing causes to an over-reliance on operator actions.

- The licensee evaluated a LOCA which used a 24 hour DG coping time using only the fuel contained in the day and belly tanks. However, the licensee determined in October of 1993 that only 11.2 hours for each DG could be assured using the contents of the day and belly tanks, combined, without refilling them.

Inclusion of these issues in the IPE has the potential to increase the overall core damage frequency, and possibly result in consideration of further engineering analysis of the issues or hardware modifications.

2.3.3 Over-Reliance on Operator Actions to Compensate for Some Design Conditions

There was an over-reliance on operator actions to meet design basis accident requirements in some cases. Although these operator actions were proceduralized, they could potentially complicate the operators' response to off-normal plant conditions. The DET found instances in which Engineering did not provide a balanced view to plant management and endorse modifications when they believed that a modification was the most effective way to resolve a problem. In response to this observation, the licensee stated that plant modifications had been discouraged resulting in an increased reliance on operator actions.

(1) Operator action would be required to protect the TDAFW pump from failure if the low pump suction trip signal was received when operating with the AFW pump turbine supplied from the alternate steam supply line. This would be required because the alternate steam admission valve (CV-0521) would not reliably close against rated steam pressure and protect the turbine. In addition, during the loss of main feedwater event, operator

action would be required to manually open a valve in a line supplying a second source of suction to the AFW pumps. This would be necessary since the CST, the primary suction source, did not contain enough water for mitigation of the loss of main feedwater event. These actions may be especially significant since they impact the two most important operator actions listed in the IPE that contribute to core damage (failure to align makeup to the CST and miscalibration of the AFW pump low pump suction pressure trip switches).

(2) For the loss of main feedwater event, operators would be required to manually operate the non-safety-related atmospheric dump valves (ADVs) or turbine bypass valves (TBVs) in order to reduce the steam pressure in the SG to 885 psig (6102 kPa) to allow the C AFW train to meet design flow rates. The C AFW pump was originally an installed spare HPSI pump and its total developed head was not sufficient to achieve rated flow at higher SG pressures.

(3) For the steam generator tube rupture (SGTR) and the main steam line break (MSLB) events on steam generator A (SG-A), the alternate steam flow path for AFW pump P-8B (from SG-B) would have to be manually initiated because operators must blow down this line to remove condensation prior to starting the AFW pump. Portions of the line are below ground with no steam traps available for condensate drainage. The routing of this line and the leakage of AFW steam supply valves caused a significant accumulation of water in this line.

2.3.4 Control and Quality of Plant Modifications Sometimes Deficient

The design, implementation and control of plant modifications were sometimes deficient, which occasionally resulted in modifications that did not achieve the intended result. The causes for the weaknesses included a historical lack of design basis information, lack of clearly defined roles and responsibilities between NECO and System Engineering, ineffective technical reviews (quality verification), and an ineffective process to assure documents, processes, and activities affected by the modification were appropriately revised. The licensee was aware of problems with the modification process. Just prior to the DE, the licensee established that NECO was the owner of the plant design basis and would be cognizant of all modifications, both major and minor. Examples of deficient modifications were as follows:

(1) There were instances where the temporary modification process should have been used but was not. The flushing of a hot spot from a drain line off of a shutdown cooling heat exchanger in 1992 was performed without using the temporary modification process. As a result, the evolution that created a change in the plant configuration was not evaluated by Engineering. The failure of the drain valve to close after flushing resulted in a 6000 gallon (22,712 liter) spill of slightly radioactive water and challenged the water inventory of the safety injection and refueling water tank. While five people and two floors of the auxiliary building were contaminated, the offsite safety

consequences of this event were low. However, it was an example of a sometimes lax and hurried approach to performing plant evolutions.

(2) In response to DET questions, Engineering found that modifications that involved mounting equipment on safety-related masonry block walls had not been controlled. For example, some structural calculations to demonstrate the integrity of safety-related masonry block walls surrounding the emergency class 1E battery rooms were non-conservative and had not accounted for later modifications made to these walls. One such modification installed a steel beam trolley, used for battery cell removal, and it had not been structurally evaluated. This lack of control of modifications necessitated an evaluation by Engineering while the DET was onsite to demonstrate that integrity of the battery room walls could be sustained during a seismic event. Subsequent engineering evaluation and non-destructive examination by the licensee showed that the walls would maintain their integrity.

(3) A design modification, SC-92-093, to a safety-related instrument bus inverter was made in 1992. The modification was in response to an event wherein safety-related recorders were operating at twice rated speed because of significant harmonic distortion in the inverter output. The licensee permanently removed vendor supplied output capacitors, which eliminated the recorder overspeed. However, the DET identified that harmonic distortion levels were still substantially above the 5 percent stipulated in the UFSAR, the vendor specification, and the DBD. The licensee concluded that this condition had not degraded equipment except for the two recorders. This problem had the potential to degrade the redundant safety related instrument power supplies.

2.3.5 Ineffective Configuration Control by Engineering

Despite the licensee's effort to improve its control of plant configuration since 1986, weaknesses still existed in the program. The weaknesses contributed to many performance problems the DET observed, including several problems with potential safety impact. Insufficient management attention, and lack of attention to details, contributed to these performance problems. Examples of the weaknesses were:

(1) The DET noted several weaknesses in the implementation of the licensee's program to control electrical load growth. Significant loads were sometimes added, either temporarily or permanently, without revising records to reflect the increased loads. The DG loading calculations were of most concern to the DET. One part of the DG loading concerns identified by the DET was that the minimum load test acceptance value identified in the TS did not include sufficient margin for instrument error when calculating the continuous LOCA loads on the DGs.

In response to the DET's concerns, the licensee re-evaluated the DG loads and determined that both DGs would potentially exceed the short time rating (2750 kw for 30 minutes) during LOCA conditions. DG 1-1 would be loaded at 2786 kw for 32 minutes and DG 1-2 would be loaded at

2802 kw for 35 minutes. At the end of the DE, while the plant was in cold shutdown, the licensee determined both DGs would have been inoperable if the plant was at power, pending further evaluation (the TS did not require DGs to be operable when in cold shutdown). In the event the short time rating was actually exceeded, increased preventive maintenance would be required. The licensee later reported, after the DET onsite evaluation was complete, that revised calculations, with more realistic assumptions for manual starting of the hydrogen recombiners and battery chargers, showed the LOCA loads to be within limits. Subsequent to the issue being found by the DET, an NRC Region III inspector found there was a lack of specific operator guidance in the emergency operating procedures on post-LOCA manual loading of equipment onto safety-related buses.

(2) On July 20, 1993, both DGs started on undervoltage signal due to the de-energization of Bus 1C, partially caused by incorrect reconfiguration of an auxiliary switch while replacing circuit breaker 152-106 with a spare (LER 93-005). This event increased the potential of injuring plant personnel and damaging equipment.

(3) The licensee's fuse control program, established in 1990-91 in response to findings of an NRC inspection in 1990, was found to have several weaknesses and was still incomplete. The weaknesses included incorrect fuse types and labelling, lack of design basis short circuit calculations for DC circuits, and lack of control of vendor supplied fuses inside vendor supplied cabinets (e.g., inverter). The plant tripped in 1992 due to an incorrectly sized fuse (LER 92-038). Weaknesses in the fuse control program increased the potential for equipment to fail upon demand during an event and exacerbate the event or to cause plant trips that unnecessarily challenge safety systems.

(4) Weak control and maintenance of vendor manuals (VM) caused problems while performing plant work.

- The reactor tripped in 1992 because of a wiring error inside an inverter resulting partially from failure to revise plant drawings and VMs after parts were replaced (LER 92-038).

- Early in 1993, safeguards transformer 1-1 feeder breaker tripped and both DGs started while the feeder breaker was replaced with a spare breaker because of the circuit configuration differences in the breakers (LER 93-005).

- Vendor recommendations regarding poor material condition of the DG and vendor recommendations regarding bearing lube oil requirements for the AFW turbine driver were not fully evaluated by Systems Engineering before deciding that no action would be taken.

- The Vendor Information Program did not ensure that updated vendor bulletins were routinely requested. Approximately 70 DG vendor bulletins which were informally received by the DG system engineer were not formally reviewed for site-specific applicability or introduced into the Operating Experience Review (OER) program for review.

- The OER program also did not require NECO be involved in decisions regarding applicability of vendor recommendations.

Probable causes for these deficiencies were attributed to weaknesses in: Engineering procedural requirements, Engineering work practices regarding maintenance and use of vendor manuals, and understanding of expectations by Engineering personnel for use of controlled information.

The Palisades Configuration Control Project (CCP) was started in 1986 and budgeted through 1997. One of the significant achievements of the CCP effort was development and reconstitution of the DBD for selected systems. Other program elements were improved since 1986. These included development and implementation of a Functional Equivalent Substitution process in 1992, a Modification Process Improvement Team initiated in early 1993, and a Multi-Discipline Review Team initiated in late 1993 to review all design modifications. Despite these efforts, the licensee agreed that weaknesses still existed and further improvements would be necessary.

2.3.6 Positive Engineering Observation

Engineering's use and field verification of the models developed for AC loadflow and DG dynamic modeling were a positive observation by the DET. AC loadflow modelling included the 345 kV switchyard through the 480 VAC loads. The licensee used this model for analyzing events and for evaluating the effects of load modifications on plant distribution systems equipment.

The licensee developed models of the DGs and ESF induction motors to simulate the transient loading conditions during LOCA load sequencing. The licensee refined these models through the use of field data that revealed, for example, that the excitation systems for the two seemingly identical DGs had different response characteristics. As a result of refinement from field data, the licensee's model correlates well with field test results for load sequencing.

2.4 MANAGEMENT AND ORGANIZATION

Significant weaknesses were identified in many areas of the organization. Lack of integrated programs and processes and clearly defined roles and responsibilities, poor communication, poor resource allocation and utilization, inadequate attention to human performance, ineffective corrective action processes, and ineffective quality oversight and self assessment resulted in poor performance and numerous repetitive events.

Management performance was evaluated in the areas of organizing, planning, directing and controlling, and solving problems. Corporate management was evaluated in areas which supported or affected station performance. The team also evaluated the timeliness and effectiveness of corrective action, self assessment, and quality oversight.

The team conducted 124 formal interviews, observed numerous meetings, reviewed relevant documents, and used the hardware and process issues discussed in Sections 2.1, 2.2, and 2.3 as a basis for evaluating management effectiveness.

2.4.1 Ineffective Management Oversight and Control

Management oversight and control was ineffective because of a lack of integrated programs and processes and clearly defined roles and responsibilities. Fragmented systems, poorly defined programs, and lack of or conflicting expectations prevented successful implementation of performance improvement initiatives. Problems experienced during normal operations continued during outage periods. Further, the length of uninterrupted power production runs was relatively short because of frequent forced outages. Managers failed to maintain a broad perspective and accept recommendations from outside sources, which obstructed good performance at Palisades.

Managers often did not recognize broader performance issues and associated consequences. Many events were caused or exacerbated by a lack of guidance and clear direction from all levels of management. An example of this situation occurred during the September 1993 primary system cooldown event. Operations supervisors did not provide adequate oversight, partially because they were occupied with competing collateral administrative duties. Management addressed tagging errors as individual personnel performance issues and did not recognize that repetitive tagging problems resulted in overall configuration control issues. Management did not consider the cumulative effect of multiple design and equipment deficiencies on system operability, plant performance and degraded safety margins. For example, management evaluated many problems on diesel generator (DG) and auxiliary feedwater (AFW) system components as unrelated, individual occurrences and did not assess the total effect on system performance or margin-to-safety. This approach to problem resolution resulted in the failure to recognize potential significant safety system degradation.

The failure of managers to recognize the consequences of broad performance issues also resulted in degraded material conditions. According to interviews of U. S. Nuclear Regulatory Commission (NRC) and Consumers Power Company

(CPCo) personnel, material condition had greatly improved since the middle 1980s because of many equipment improvements, including replacement of the steam generators, and increased housekeeping efforts. However, ineffective modifications, inadequate repairs, poor maintenance practices, weak component and system testing, configuration control problems, and poor engineering support described previously contributed to ongoing degraded material conditions. Numerous examples of degraded material conditions and poor housekeeping were identified by the team and the licensee during the evaluation.

Performance at Palisades declined, in part, because of a lack of outside perspective. During interviews, current and former senior CPCo managers informed the team that useful information and recommendations from outside industry and regulatory groups had often not been accepted and utilized at Palisades. New senior managers stated that they had noted a somewhat confrontational relationship between CPCo personnel and these outside groups. Consequently, Palisades only compared its performance with its past performance. This resulted in the perception that current performance was acceptable and improvements were not required. This perception had also been communicated to the staff by Palisades management.

2.4.1.1 Lack of Integrated Programs and Processes

Fragmented systems or processes in planning, corrective actions, configuration control, and management information systems (MIS) coupled with poor communication produced a lack of functional integration between departments which resulted in poor performance and a lack of teamwork. Palisades managers recognized this problem and used the term "functional silos" to describe it. Poorly defined programs and policies resulted in plant operations and events that challenged safety systems and equipment. In several instances, managers did not completely plan and develop programs and processes, nor fully train plant staff, before implementation.

The licensee had not integrated many site activities into an organized plan; to scope, schedule, and resource load these activities; to provide for overall oversight and control; to accomplish activities to a recognized time table; and to require followup, closeout reporting and accountability. Each department had a separate listing of planned or proposed activities. Accomplishment of these activities was dependent on available resources, which fluctuated because of emergent work and changing priorities in response to external influences. This situation fostered a station-wide reactive approach to planning and resulted in significant delays and in some cases, incomplete or abandoned projects and corrective actions. For example, several hardware problems and weaknesses were identified by the licensee during its Design Basis Documentation review program and by the NRC during the Electrical Distribution System Functional Inspection. The team found that many of these issues had not been acted on in a manner commensurate with their safety significance.

Lack of an integrated configuration control process resulted in significant engineering issues and events. For example, poor programmatic guidance resulted in operating procedures, plant drawings and vendor manuals that were not properly updated following modifications and changes to safety-related systems and components. Several operational events reported in 1993 and 1994 involved weak configuration control. The licensee failed to appropriately address long-standing equipment tagging problems which resulted in configuration control issues and contributed to numerous events.

MISs were not integrated and lacked compatibility. Each department maintained its own MIS and associated data base. In January 1994, the licensee attempted to collect and document all current and pending work activities at Palisades. This effort was abandoned because the information maintained in the MIS for each department was inconsistent and the database formats were incompatible. According to interviews, although an integrated MIS improvement plan was developed and funded in 1992, the plan was postponed in 1993 because of cost concerns related to the outage.

Communication problems were widespread. Both vertical and horizontal communication were ineffective and were previously identified as a root cause of poor performance by the licensee. The licensee had proposed a corrective action plan in late 1992, developed a plan in mid-1993, but had never fully implemented the plan. Numerous events were caused or exacerbated by poor communication. Poor communication between operators in the control room and personnel raising the reactor vessel head contributed to raising the head with a control rod attached in 1993. Many of the observations documented by the team were caused or exacerbated by poor communication.

Poorly defined programs and conflicting expectations led personnel to make poor decisions. Only one paragraph in Administrative Procedure 3.03, "Corrective Action," gave guidance for operability determinations. Site managers stated that Operations personnel were expected to make an immediate operability determination; however, in some cases, Operations managers were not aware of operability concerns until a corrective action document was presented at the Corrective Action Review Board (CARB) meeting. This delay in informing Operations of operability concerns ranged from overnight to several days. Additionally, Operations rarely documented operability decisions or the basis for these decisions. System Engineering or Nuclear Engineering and Construction Organization (NECO) personnel performed the analyses; however, Licensing personnel performed the final review. The team observed, during CARB meetings, that Licensing arguments often prevailed over engineering and safety performance concerns. For example, on March 21, 1994, the safety concerns of the system engineer assigned to investigate the effects of fully engaged alignment bolts on the operability of safety-related pumps were overridden by Licensing's views. The team also observed that operability determinations that resulted in a component or system declared "inoperable" were met with close scrutiny, while "operable" determinations were accepted readily. Several questionable operability decisions were identified, including issues regarding reactor protection system cable separation, condensate storage tank water temperature, and DG air start motors.

Frequently, managers did not completely plan and develop programs and processes, nor fully train plant staff, before implementation. Therefore, these processes and programs were ineffective and did not meet their intended goals and objectives. Problems with the reorganization of the Quality

Assurance Department to become the Nuclear Performance Assurance Department (NPAD) and the move of NECO to the site and its relationship to Systems Engineering were caused by the failure of managers to rigorously plan, develop, and train before implementation of these changes.

The licensee had some success when using task force or special team project management techniques. However, the licensee often did not transfer ownership of the task force's solution back to the line organization. Thus, some action items and recommendations produced by task forces were not acted on when the task force was completed or disbanded. For example, the Pressurized Thermal Shock program lost momentum after the task force was disbanded and the program was reassigned to an individual in NECO. Over 80 active task forces existed for myriad purposes, ranging from the control of individual component repair to program development.

2.4.1.2 Lack of Clearly Defined Roles and Responsibilities

Lack of clearly defined roles and responsibilities coupled with ineffective communication and conflicting expectations led to poor performance and unsuccessful implementation of performance improvements. Confusion regarding the role of NPAD resulted in weak assessments that were directed at minor industrial safety and schedular conformance issues, rather than uncovering existing program and process deficiencies, human performance problems, and safety concerns. Unclear guidelines and expectations concerning the roles and responsibilities between System Engineering and NECO resulted in issues generated by design basis document reviews, such as the increase in DG fuel oil consumption, remaining unresolved. System engineers did not communicate effectively with NECO engineers, whose input was often not sought when needed.

Management communicated conflicting expectations. Consequently, attention to safety was weak in some cases. Management's stated objective was safety; however, personnel performance evaluations were based on meeting financial and schedular goals. Front line supervisors often recounted during interviews with the team that management gave highest priority to meeting schedules.

2.4.1.3 Problems During Normal Operations Continued Through Outage Periods

The causes for problems and events observed during outages were not unique to outage periods. The causes included ineffective communication, coordination, scheduling, planning, supervisory oversight, project management, and poor implementation of lessons learned. These causes, along with weak oversight of work performed by contractors and CPCo organizations, contributed to the problems during normal operations and outages. Problems during normal operations that continued under outage management included procedure adherence, lack of configuration controls, human performance issues, and lack of a questioning attitude.

Until the 1993 refueling outage, outage management was a function within the Operations and Outage Department. The Operations and Outage Department Manager had the dual role of supervising plant operations while preparing for the next outage period. The competing requirements of these roles caused a span of control problem which was recognized by licensee senior management.

Site management implemented a plan in 1993 to restructure the Operations and Outage Department. This plan was designed to allow the Operations Manager to concentrate attention on solving plant operational problems and appeared to accomplish this objective. However, the position of Outage Manager remained unfilled as of April 1994. Consequently, planning for the 1995 outage was behind schedule.

Controls and programs were ineffective or not properly implemented in certain technical areas associated with outages and power operations. For example, a NPAD audit found that the licensee missed the broader root cause for the poor plant and corporate reviews of the weld procedure specification that affected welding parameters and examinations. The broader issue was a potential programmatic change to ensure appropriate reviews were performed on corporate procedures used at Palisades. The lack of programmatic controls, when combined with ineffective configuration management, caused numerous events and deficiencies during outages and power operations. For example, the personnel protective tagging on the incoming electrical supply line from the D.C. Cook Nuclear Power Station (the "Cook 2 line") was never hung as required for work performed during February 1994. This condition was not discovered until restoration of the line was implemented.

Lack of supervisory control over onsite contractor activities caused many problems and events, particularly when the contractors did not comply with site procedures and practices. For example, contractors missed procedural hold points and double verifications, incorrectly used load cells to lift the upper guide structure during refueling, incorrectly installed some pipe hangers, ineffectively accomplished technical calculations, and improperly terminated wires. The licensee did not complete corrective actions, which included training responsible contract project managers in contractor oversight. The licensee last performed training in this area in August 1992.

The licensee did not formally implement outage management guidelines to increase the defense-in-depth and reduce risk during outages. The documents describing the licensee's program contained numerous undefined terms and conditions which were subject to interpretation. Terms not defined included "as long after shutdown as practical," "maintained as high as practical," "normally operable," "maintained as much as possible," and "in service as much as practical." The team performed a general review of the outage control program and determined that the licensee had not fully executed an outage shutdown risk program, and had not addressed all of the findings from its own 1993 selfassessment of the outage shutdown risk program.

2.4.1.4 Poor Resource Allocation and Utilization

The poor planning, allocation, and utilization of resources and a lack of succession planning and defense-in-depth resulted in strained staffing and large backlogs in some key areas. MIS and budget processes did not provide managers with effective decision-making tools to adjust resources. Staffing shortages in several areas were not addressed despite indications of performance degradation. The lack of staff in corrective actions and human performance evaluation areas impeded effective implementation of these programs.

Strained staffing and management's failure to recognize the problems with large procedure change backlogs resulted in several examples of deficient and confusing operating procedures. Operations procedure writers routinely postponed non-emergency changes to coincide with required biennial reviews because of heavy work loads resulting from excessive collateral duties. Operations supervisors were also assigned procedure revision responsibilities as collateral duties. During the last biennial review, several hundred requested procedure changes, some more than 2 years old, were not incorporated. Subsequent to team identification of this problem, licensee management increased the staffing in this area.

A large safety-related work request backlog was awaiting planning. Some work requests had awaited planning since 1989 and a few high priority work requests from 1990 had yet to be planned.

Management did not plan for the replacement of some key personnel, which delayed resolution of safety concerns. Vacancies in key program oversight positions, or replacement of experienced supervisors with junior or marginally qualified personnel, contributed to identified engineering and maintenance weaknesses in the programs for Inservice Testing, air operated valve testing, relief valve testing, and the seismic qualification of plant equipment under the Seismic Qualification Users Group. Many of these vacancies were budgeted positions. Site managers stated during interviews that staffing levels were routinely allowed to be below budgeted allocations.

2.4.2 Inadequate Attention to Human Performance

Plant management failed to address and correct human performance problems despite numerous indications that these problems prevented successful completion of activities and caused operational events. Root cause evaluations continued to identify human performance issues as an increasing trend, yet no systematic approach existed to address these issues. Internal reports from NPAD and its predecessor organization clearly portrayed a site-wide problem in human performance since the late 1980s.

Senior management delayed responding to a 1992 industry initiative to enhance human performance despite self-identified significant problems with human error causing poor procedural adherence, incorrect valve manipulations, and fuel-handling problems. Plant management did not give high priority to resolving the Human Performance Improvement Committee issues and formulating corrective actions to address these issues.

The licensee's implementation of the Human Performance Enhancement System (HPES) had neither identified the underlying causes for repetitive human errors nor directed senior management's attention and resources on reducing the organizational barriers to enhanced performance. Further, the program's effectiveness was constrained by the assignment of a large number of evaluations without a commensurate increase in staffing or resources. A single HPES Coordinator was assigned to complete a steadily increasing number of evaluations which substantially reduced the amount of time being spent to review and analyze each event and decreased the quality of the evaluation.

The number of assigned evaluations steadily increased from 20 in 1992 to over 100 in 1993. As of March 1994, 60 HPES evaluations were assigned in 1994.

Difficulty in following procedures was the cause of numerous events because management did not appreciate the importance of clearly written procedures, and did not encourage taking immediate corrective action when a procedure did not support the required task. Site management received reports from NPAD, the Industry Events and Assessment Group, and the Corrective Actions Group stating that a high percentage of events were caused by procedural adherence problems. NRC reports repeatedly highlighted similar problems to Palisades management. Operators and technicians stated in interviews that they were given the latitude to compensate for procedural inadequacies if they understood the intent and were able to comply with the objectives. Therefore, plant personnel routinely substituted individual knowledge, skill-of-the-craft, and training for poorly worded or inaccurate procedural steps. Consequently, procedural adherence continued to be a problem at Palisades and resulted in numerous events.

Management and supervisory skills had not been methodically taught or formally developed despite the occurrence of numerous events where weak management skills were identified as a direct or contributing causal factor. While this problem existed throughout the organization, the problem was particularly acute in the Operations Department. Few Operations personnel had taken any management or supervisory courses after their initial shift supervisory training.

Management's lack of perspective on human performance problems affected the Individual Plant Examination (IPE). The IPE model did not reflect the heavy reliance on operator actions to compensate for degraded equipment or weaknesses in plant design. The team found that inordinate credit was taken for operator actions to compensate for equipment and component failures without providing the responsible staff with appropriate training and procedural guidance. The IPE used industry standard human error rates and did not conservatively apply industry models. Consequently, the licensee may have underestimated the contribution of human error to overall plant risk, especially when coupled with the poor operator performance and procedure inadequacies previously identified.

2.4.3 Ineffective Corrective Action Process

The licensee established a high threshold for identifying deficiencies. The team identified many instances in which the licensee did not recognize and document problems, performed shallow root cause analysis, and performed ineffective or untimely corrective actions. These problems significantly contributed to degraded performance and prevented the licensee from taking decisive corrective action on a wide range of safety issues.

Many conditions that met the procedural criteria for the site-wide deficiency reporting system were never reported under this system. Several departments had separate deficiency reporting systems that were intended to track problems that did not meet the threshold of the deficiency report (DR). However, the team found during reviews of these departmental tracking systems that site supervisors throughout the organization frequently did not elevate deficiencies into the site-wide corrective action tracking system. This was confirmed during interviews. Additionally, several interviewees stated that when they identified a problem, they were assigned the responsibility to correct the identified problem. As a result, operators stated that there was a general reluctance to report problems unless they resulted in equipment damage or were discovered by Operations supervisors.

Even after problems were identified, management occasionally did not recognize the safety significance of issues. Additionally, the CARB did not facilitate problem identification or resolution. Plant Safety and Licensing personnel often dispositioned identified problems by making restrictive and nonconservative interpretations of the current license bases without stating or considering the safety bases for their conclusions. Plant management facilitated and encouraged this situation.

Root cause analysis efforts often did not distinguish the underlying causes of events and deficiencies. The root cause sections of the corrective action reports were often superficial and contained only cursory insight into the underlying causes of the performance deficiency. Root cause determinations were limited to shallow descriptions of events or individual errors and often failed to provide insights to station managers regarding programmatic weaknesses and human performance hindrances. Root cause evaluators had often not completed formal training and as a result, conducted event investigations inconsistently or ineffectively.

Management's delay in addressing long-standing design basis issues reduced safety margins in some instances. The early design of Palisades was found to require improvement as operating experience identified a general lack of design margins in key safety systems during the late 1970s. For example, the licensee installed an additional AFW pump and increased the size of the low pressure safety injection pump impellers in response to identified design margin weaknesses and NRC concerns. Senior management did not have a conservative perspective on the limited safety margins in the original design. Many of the problems that were identified by the team and discussed in other sections of this report were directly related to previous modifications and early decisions that were not well conceived or poorly designed. The attempt to reconstitute the original design bases demonstrated recognition of this situation and the action indicated intent to understand the problems. The new senior management team recognized continuing problems and the need for the development of an action plan devoted to resolving design basis issues as part of the broad Palisades Performance Enhancement Plan (PPEP).

2.4.4 Ineffective Quality Oversight and Self Assessment

NPAD, Palisades' quality oversight group, and departmental self assessment groups often did not perform detailed, effective technical assessments. Persons in certain key positions within NPAD were marginally qualified in the area being assessed. Additionally, even when NPAD and departmental assessments contained insightful findings, line managers frequently did not respond effectively to the observations and recommendations. The methods of measuring performance were subjective and ill-defined, in some cases.

Many of the NPAD assessments lacked the depth, detail and insight required to fulfill the quality oversight role. Many NPAD assessors made findings and observations that were primarily focussed on issues that had little, if any, safety significance. The team identified several generic problems that had not been recognized by NPAD in its assessments, such as the weaknesses in the maintenance and testing area; the continued, pervasive problems with configuration control; and the operability process problems. NPAD assessors lacked the experience and background necessary to evaluate plant operations, which resulted in minimal findings.

NPAD was ineffective in raising problems and concerns to the appropriate managers to ensure adequate resolution. Managers often did little to resolve assessment findings in such key areas as weak human performance, poor adherence to work instructions, policies and plant practices, and loss of skilled plant personnel without trained replacement.

The Operations Department performed limited and ineffective self assessments. Minimally significant findings or improvements resulted. The Maintenance and site Engineering Departments had not recently performed self assessments. In addition, the quality verification (QV) program which was implemented in July 1992, was not uniformly integrated except within the Maintenance Department. QV was inconsistently implemented in the Operations and Engineering Departments where operators and plant personnel often incorrectly completed QV activities which contributed to poor quality products and performance.

The measurement and analysis of performance indicators was inconsistent and potentially misleading. Consequently, site managers were not fully cognizant of actual daily performance trends and lacked the information needed to assess and resolve problems. For example, some corrective maintenance activities were incorrectly reported as preventive maintenance and NPAD did not have valid performance indicators to verify yearly goals and objectives were met.

In early 1994, the licensee established the Management and Safety Review Committee to provide a critical outside perspective to the management and safe operation of Palisades. During the first meeting in March 1994, this small group of industry consultants and managers from CPCo and Palisades was chartered to periodically review safety activities and report to senior management of CPCo. The effectiveness of the Committee, because of its recent formation, was not evaluated by the team.

2.4.5 Positive Observations

In early 1994, the licensee recognized the need to improve safety performance and formed a new senior management team to address the significant problems that needed correction, and formulated and implemented a plan to resolve these issues. During the period of the DE, the licensee expanded its plan to include additional issues that were being identified by the team. This resulted in the development of the Palisades Performance Enhancement Plan (PPEP). The PPEP addressed six major areas which included leadership and management, process improvement, human performance, culture, critical assessments and plant condition. When completed, each of the six major areas would be supported by associated action plans. The overall approach used in the PPEP included the major areas, goals and objectives, action plans, deliverables, lessons learned, references, and performance indicators. At the conclusion of the DE, the licensee was continuing to modify and develop the PPEP and associated action plans. The team was unable to evaluate the effectiveness of the PPEP because of its early stages of development and lack of implementation. However, the team did review the major areas, goals and objectives, and certain initial PPEP action plans. The team determined that the PPEP appeared to be appropriately focused on the performance issues that required lasting resolution to effect needed plant improvement.

The acknowledgement of problems and the initial approach taken to develop and implement this program by Palisades and CPCo management was a positive observation. This new senior management team appeared to have brought with it higher expectations and standards and overall improved management skills.

3.0 ROOT CAUSES

3.1 Acceptance of Low Standards of Performance

Prior to Spring 1994 most managers and staff at Palisades had been long-term employees of CPCo and did not have commercial nuclear experience outside the company. In addition, neither corporate nor site management encouraged the review of industry programs and performance standards and comparison of those to Palisades. Consequently, managers did not have or use outside perspectives to judge plant performance. This significantly hampered their ability to recognize weak performance and programs that needed improvement. It also resulted in management's denial of problems found by outsiders and a somewhat confrontational relationship with those outside entities. Worse yet, plant staff's awareness of its management's views, and management's reassurance to the staff that their performance was not in need of improvement, prolonged the problems.

The effects of low performance standards were evident throughout the organization. Operations management failed to recognize or accepted lack of rigorous adherence to procedures, inconsistent procedure quality, test results that did not always meet acceptance criteria, and poor material condition of the plant. Site and Engineering management failed to recognize or accepted poor timeliness and quality of engineering evaluations and support to the plant, and recurring lack of control of engineering contractors. Maintenance management failed to recognize or accepted poor maintenance practices.

3.2 Failure to Integrate Processes and Clarify and Communicate Roles and Responsibilities

Management did not clearly identify and communicate to plant staff and department heads the roles and responsibilities of organizational components. This, coupled with a lack of integrated programs and processes across the organization, resulted in confusion and lack of ownership of problems. Lack of clearly defined roles and responsibilities between Nuclear Engineering and Construction Organization (NECO) engineers and system engineers often resulted in weak support of Operations and Maintenance in resolving operational problems and evaluating degraded plant conditions. Also, prior to its assignment in spring 1994 as the design authority for Palisades, NECO's responsibility for this important function was unclear and sometimes was abrogated to Systems Engineering or engineering contractors. The unclear roles and responsibilities of the Nuclear Performance Assessment Department (NPAD) relative to the line organization resulted in problems not being identified by either organization in many instances. Additionally, when problems were identified, they were not always acted upon by the line organization, nor were they rigorously tracked by NPAD to ensure that they were satisfactorily resolved.

Management's failure to clarify and communicate roles and responsibilities led to inconsistent interpretation by organizations and individuals. Stronger organizations and individuals took on expanded roles, while weaker ones were content with lesser roles. This situation, coupled with low standards of performance, allowed certain groups and individuals to more heavily influence decisions without plant management's providing effective oversight and challenging the soundness of those decisions. For example, Licensing took a lead role and was heavily relied on for determining equipment operability, sometimes unduly raising the importance of licensing basis perspectives over the safety concerns of other plant organizations.

3.3 Failure to Ensure Effective Self Assessment and Quality Oversight

Self assessment by the line organization was ineffective for several reasons. Site management did not promote a questioning attitude among the staff, accountability at many levels of the organization was weak, and implementation of the self checking and independent verification functions under the Quality Verification Program (QVP) was inconsistent within and among several departments. This resulted in human performance and programmatic weaknesses that continued uncorrected for several years. Safety tagging and procedural adherence problems in Operations continued to occur without Operations management focusing on the broader aspect of these problems, and not addressing weak implementation of the QVP as a root cause requiring corrective action. Maintenance management did not identify the many weaknesses that the team found. In fact, they were unaware that most of their personnel were not rigorously implementing the relatively new Maintenance policy that required individuals to walkdown their assigned spaces to identify problems with material condition. Engineering management did not identify the broad performance problems that existed within their organizations.

Independent quality oversight by NPAD was ineffective because its interface with the line organization and its role were not clearly defined by site management. Furthermore, NPAD was staffed with individuals not well qualified in the development and conduct of performance based technical audits and assessments, which resulted in poor quality findings. This contributed to a lack of respect by the line organization for NPAD, creating a situation in which even the substantive findings of NPAD were not aggressively addressed by the line organization in many instances. NPAD did not assert itself to require accountability by the plant to respond to its findings, and site management did not fully endorse NPAD's role to ensure that this occurred.

3.4 Failure to Develop and Implement an Effective Corrective Action Process

The corrective action process was ineffective because of weaknesses in problem identification, resolution, and corrective action implementation. The high threshold for problem identification, the frequent assignment of problem resolution to the individual who identified it, and the lack of rigorous corrective action implementation by management in some cases provided a message to the staff that management did not want to find and resolve problems. The high threshold for problem identification also resulted in the development and use of fragmented department-level corrective action systems that used different databases and priorities and which were not integrated into the plant-wide system. Problems were not effectively resolved in many instances because management did not promote a questioning attitude in the staff. In addition, plant staff was provided limited training in root cause analysis and event investigation techniques, resulting in many instances of poor quality root cause determinations. Corrective actions were not rigorously tracked and prioritized across the plant because site management had not developed and implemented an integrated corrective action system. Management information systems were not designed and appropriately reviewed by management to provide useful feedback on the status of implementation of corrective actions. This resulted in many corrective actions not being completed, only partially completed, or languishing on a list of actions yet to be accomplished.

4.0 Exit Meeting

On May 31, 1994, the Deputy Executive Director for Nuclear Reactor Regulation, Regional Operations and Research; the Directors of AEOD, NRR, the Administrator for Region III; the Manager of the Palisades Diagnostic Evaluation Team; and other NRC staff members met with the Chairman CPCo; the President and Chief Executive Officer, CPCo; the Senior Vice President, Nuclear, Rates, and Marketing, CPCo; the Vice President, Nuclear Operations, CPCo; the Palisades General Plant Manager; and senior managers and staff from the Palisades plant to review the results of the evaluation. This exit meeting was open for public observation. Briefing notes summarizing the team findings and conclusions are attached as Appendix A.

DIAGNOSTIC EVALUATION

EXIT SLIDES

ON

PALISADES NUCLEAR GENERATING FACILITY

MAY 31, 1994

U.S. Nuclear Regulatory Commission
Office for Analysis and Evaluation of Operational Data
Division of Operational Assessment
Diagnostic Evaluation and Incident Investigation Branch

SELECTION OF PALISADES BASED ON

- Indications of Weaknesses in Management and Programs
- Decline in Performance in SALP Reports
- Recent Operational Events
- Repetitive Hardware Problems
- Procedural Violations
- Indications of Ineffective Self-Assessment
- Organizational Performance Problems Not Well Understood

DET GOALS AND OBJECTIVES

- Provide Information to Supplement Other Assessment Data Available to NRC Senior Management
- Evaluate Licensee Staff and Management Involvement and Effectiveness with Respect to Safe Plant Operation
- Evaluate the Effectiveness of the Licensee's Self Assessments, Corrective Actions, Improvement Programs and Plans
- Determine the Root Causes of Safety-Related Equipment and Performance Problems

DET METHOLOGY

- 15-Member Team: 3-OPS, 4-M&T, 4-ENG, 4-M&O
- 5-Week Evaluation: 3 Weeks On-site, 2 Weeks In-office
- Over 120 Interviews Conducted from COB/CEO to RPO
- 3 Days of Near Round-the-Clock CR Observation
- Indepth Review of 2 Systems and Their Subsystems

OPERATIONS WEAKNESSES

* POOR PLANNING AND DIRECTION BY OPS MANAGEMENT

* POOR ONSHIFT SUPERVISORY OVERSIGHT

* LOW PERFORMANCE EXPECTATIONS

* REPETITIVE PROTECTIVE TAGGING PROBLEMS

* OPS POORLY SUPPORTED BY LICENSING, ENGINEERING, & TRAINING

* WEAK SELF ASSESSMENT & CORRECTIVE ACTION

OPERATIONS
<u>POSITIVE OBSERVATIONS</u>

IMPROVED TRAINING IN SOME AREAS

FORMAL PRE-JOB BRIEFINGS

FREQUENT REPORTING OF MAJOR OPS CONCERNS
TO SITE VP

MAINTENANCE AND TESTING WEAKNESSES

* WEAKNESSES IN COMPONENT TESTING TO DEMONSTRATE OPERABILITY

* ~~PROGRAMMATIC BREAKDOWN OF PUMP AND VALVE TESTING~~ [1]

* PUMP AND VALVE TESTING WEAKNESSES [1]

* WEAK MAINTENANCE WORK PRACTICES

* MATERIAL CONDITION DEFICIENCIES NOT IDENTIFIED & DOCUMENTED

* POORLY CONTROLLED STORAGE OF SAFETY RELATED MATERIAL

* POOR SUPPORT FOR PREVENTIVE MAINTENANCE IMPACTED EQUIPMENT PERFORMANCE

* WEAK MAINTENANCE WORK ORDER TRACKING AND REPORTING

---

[1]Based on review of additional information provided by the licensee and detailed discussions between the team and NRC staff, the collective weaknesses identified in the testing area were determined by the team to not constitute a programmatic breakdown.

MAINTENANCE AND TESTING
POSITIVE OBSERVATION

QUALITY AND COMPLETENESS OF MATERIAL HISTORY DOCUMENTATION

ENGINEERING SUPPORT WEAKNESSES

* WEAK PLANT SUPPORT FROM ENGINEERING

    * OPERABILITY & ROOT CAUSE DETERMINATIONS

    * PROCEDURES

* UNTIMELY AND INEFFECTIVE PROBLEM RESOLUTION

* OVER-RELIANCE ON OPERATORS IN PREFERENCE TO MODIFYING THE PLANT

* DEFICIENT CONTROL AND QUALITY OF PLANT MODIFICATIONS

* INEFFECTIVE CONFIGURATION CONTROL

ENGINEERING SUPPORT
<u>POSITIVE OBSERVATION</u>

DEVELOPMENT AND USE OF AC LOAD FLOW AND DG DYNAMIC MODELS

MANAGEMENT AND ORGANIZATION WEAKNESSES

- INEFFECTIVE MANAGEMENT OVERSIGHT AND CONTROL
  - PROGRAM INTEGRATION
  - ROLES & RESPONSIBILITIES
  - RESOURCE ALLOCATION AND UTILIZATION
- INADEQUATE ATTENTION TO HUMAN PERFORMANCE
- INEFFECTIVE CORRECTIVE ACTION PROCESS
- INEFFECTIVE QUALITY OVERSIGHT AND SELF ASSESSMENT

MANAGEMENT AND ORGANIZATION
POSITIVE OBSERVATIONS

NEW LEADERSHIP TEAM - HIGHER EXPECTATIONS AND RECOGNITION OF NEED TO IMPROVE

PALISADES PERFORMANCE ENHANCEMENT PROGRAM - APPEARS TO BE APPROPRIATELY FOCUSED - EFFECTIVENESS NOT EVALUATED BY TEAM

ROOT CAUSES

ACCEPTANCE OF LOW PERFORMANCE STANDARDS

FAILURE TO INTEGRATE PROCESSES AND CLARIFY ROLES & RESPONSIBILITIES

FAILURE TO ENSURE EFFECTIVE SELF ASSESSMENT & QUALITY OVERSIGHT

FAILURE TO DEVELOP AND IMPLEMENT EFFECTIVE CORRECTIVE ACTION PROCESS