U.S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-255/96002

FACILITY
Palisades Nuclear Generating Plant

LICENSEE
Palisades Nuclear Generating Plant
27780 Blue Star Memorial Highway
Covert, MI 49043-9530

DATES
January 27 through March 17, 1996

INSPECTORS
M. Parker, Senior Resident Inspector
P. Prescott, Resident Inspector
J. Neisler, DRS Inspector
J. Cameron, DRS Inspector
S. Burgess, DRS Inspector
A. Dunlop, DRS Inspector
J. Guzman, DRS Inspector
M. Holbrook, NRC Consultant, INEL

APPROVED BY

for W. J. Kropp, Chief
Reactor Projects Branch 3

4-2-96
Date

AREAS INSPECTED

A routine, unannounced inspection of operations, engineering, maintenance, and plant support was performed. Safety assessment and quality verification activities were routinely evaluated. In addition, on January 8-12, 1996, an announced safety inspection of the licensee's response to Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve (MOV) Testing and Surveillance," (2515/109) and the licensee's self-assessment in this area was conducted.

EXECUTIVE SUMMARY

OPERATIONS (Section 1.0).

The licensee has made significant progress in identifying deficient conditions. The corrective action process has been instrumental in assisting the utility to identify and address corrective actions. INSPECTOR IDENTIFIED

Three reactivity management issues occurred this period: excessive power rate increase, exceeding licensed steady state thermal power, and minor dilution of the primary coolant system. These issues involved personnel error, procedural error, and equipment problems and indicate that additional attention is still needed in these areas. INSPECTOR/LICENSEE IDENTIFIED

On February 7, 1996, licensee exceeded licensed maximum steady state thermal power limits (2530 Megawatts) over a nine and one-half hour period. (Section 1.2) INSPECTOR IDENTIFIED

MAINTENANCE (Section 2.0).

A significant chemical spill along with an unmonitored discharge to the environment occurred during this period due to poor plant material condition. The caustic spill had the potential for personnel injury. (Sections 1.4 and 1.5) SELF-REVEALING

ENGINEERING (Section 3.0).

Management oversight of the GL 89-10 program was effective since the Part 2 inspection. NRC IDENTIFIED

- Notable improvements included the focus on the core MOV team to technically strengthen the program, complete the testing, and achieve program closure.
- Program documentation and test data provided an adequate basis to conclude that all GL 89-10 program MOVs would perform their intended safety functions under worst-case design-basis conditions.
- A weakness was noted in the rigor in obtaining best available data for valves that were not dP tested.
- One unresolved item was identified concerning 20 inoperable MOVs after a postulated Appendix R fire scenario (Section 3.2.8).
- Self-assessments in the MOV area consistently provided good technical findings and effectively monitored the progress made toward program closure (Section 3.2.13).

PLANT SUPPORT (Section 4.0).

The overall assessment of plant support was adequate. The licensee has implemented plans to improve overall radiation worker (radworker) performance. NRC IDENTIFIED

Summary Of Open Items

Unresolved Items: identified in Section 1.2 and 3.2.8

INSPECTION DETAILS

1.0 OPERATIONS

NRC Inspection Procedures 71707 was used in the performance of an inspection of ongoing plant operations.

1.1 Excessive Power Escalation Rate

On January 31, 1996, during a power escalation following a forced outage to replace a safeguards bus cable, the licensee exceeded their administrative limits for power rate increase over a one hour period. Between 7:00 p.m. and 8:00 p.m. on January 31, 1996, with reactor power at approximately 77 percent, the power rate increase was recorded at 6.7 percent. General Operating Procedure (GOP) - 5, Power Escalation After Synchronization, Attachment 5, specifies 6 percent per hour as the maximum recommended escalation rate limit with thermal power between 35-90 percent. During the dilution evolution to raise reactor power, the reactor operator believed that adequate steps were being taken to control the power escalation rate and decided to perform an extra dilution of the primary coolant system (PCS). This resulted in a power level rise of 2 percent over a 10 minute period. This action was taken without consulting other members of the shift; specifically, the control room supervisor (CRS) or the shift engineer who was monitoring the power rise every 15 minutes. The operator did inform the CRS of his intent to perform a dilution, but there was no discussion of the amount of the dilution.

In reviewing the impact of the power escalation rate, the inspectors discussed the administrative recommended rate increase with reactor engineering. Their review determined that there was no impact to the fuel as a result of the rate increase. The fuel vendor has no rate limits below 90 percent power with preconditioned fuel. The limit was provided as a reasonable rate of increase during power escalation.

The root cause of exceeding the recommended rate limit appeared to be inadequate communications between the reactor operator and the control room supervisor, and inadequate training on the specific evolution. The licensee has taken action to provide specific training on control of the plant during power escalations and has also provided a Reactivity Standard to the shifts that specifies required actions and expected response during power escalation activities.

1.2 Licensed Steady State Thermal Power

1.2.1 Exceeding Thermal Power Level

On February 8, 1996, the reactor engineer reviewed power history records and noted that the plant had exceeded its licensed thermal power output of 2530 MW (100 percent rated thermal power) averaged over an 8 hour shift.

On February 7, 1996, with the plant operating normally at full power, a one hour delithiation period was started in accordance with plant procedures to control primary coolant system (PCS) pH. The delithation process was initiated at 9:30 a.m. and secured at 10:56 p.m.. Since the delithiating process could affect reactivity due to the resin's affinity for boron, the operating crew monitored for reactivity changes and anticipated an increase in reactor power. Average power had been running near 99.8 percent since the beginning of the shift. The operating crew had fully anticipated that reactor core thermal power levels could increase, but expected that the 24 hour average power limits of General Operating Procedure GOP-12, " Heat Balance Calculation," would be maintained. During the evolution from 10:40 a.m. to 8:00 p.m. on February 7, 1996, reactor thermal power exceeded maximum licensed thermal power level of 2530 MW. Peak power level recorded was 100.4 percent and the maximum 8 hour average power level was 100.2 percent, with the maximum 8 hour shiftly average power level recorded at 100.1 percent. However, reactor power did not exceed the licensees administrative limits specified in GOP-12, revision 12, dated November 16, 1996, which states:

a. Reactor power shall be maintained less than or equal to 100.99 percent (2555 MWt) at all times. If 100.99 percent is exceeded, then reactor power shall be immediately reduced to ≤ 100.99 percent and a condition report shall be initiated.

b. The daily (0000-2300) average of plant process computer (PPC) calorimetric values shall be less than 100.00 percent. A condition report shall be initiated if this limit is exceeded.

c. The shiftly average of hourly PPC calorimetric values should be less than 100.00 percent, but immediate action to reduce power is not required unless necessary to ensure a. or b. are met.

Palisades Plant Facility Operating License section, 2.C.(1), Maximum Power Level, states that "The licensee is authorized to operate the facility at a steady-state reactor core power levels not in excess of 2530 Megawatts thermal (100 percent rated power) in accordance with the conditions specified herein."

The NRC staff has recognized brief power excursions above licensed thermal power limits, provided the average power level over any 8 hour shift is maintained no greater than the 100 percent limit. This issue is considered an unresolved item (50-255/96002-01(DRP)) pending further review by the NRC staff.

The inspectors have reviewed this issue with the licensee, and the licensee has provided additional operating instructions to licensed operators. GOP-12 has been revised to require operators to maintain reactor power below 2530 MWt (licensed thermal limits) at all times.

1.2.2 <u>10 CFR 50.59 Evaluation</u>

During the review of the event described above, the inspectors identified that General Operating Procedure (GOP)-12, "Heat Balance Calculation" did not comply with design basis documents (10 CFR 50, Appendix K and Final Safety

Analysis Report). The procedure allowed reactor power to go up to 100.99 percent based upon an instrument/measurement uncertainty of ± 25 MWt (± 1 percent). 10 CFR 50, Appendix K, "ECCS Evaluation Models," assumes that the reactor has been operating continuously at a power level of at least 1.02 times the licensed power level to allow for such uncertainties as instrumentation error. Also, the Final Safety Analysis Report (FSAR), Chapter 14, "Safety Analysis," Section 14.1.3, Analysis Performed at 2530 MWt, states that the initial conditions for transient analyses are based on steady-state operations at 2,530 MWt with the following uncertainties applied to ensure conservative analysis: reactor power ± 2 percent.

The 10 CFR 50.59 screening in December 1993, to determine if there was an unreviewed safety question (USQ) was inadequate for the GOP-12 revision 7, that incorporated a ± 1 percent uncertainty value versus a ± 2 percent uncertainty value. Two engineering analyses (EA-HAR-91-01 and EA-HAR-91-10) were performed to confirm that a ± 2 percent uncertainty existed following replacement of steam generators and changes in operating parameters. Both analyses confirmed that the instrument uncertainties were within ± 2 percent (actual ± 1.90 percent and ± 1.91 percent). During a revision to GOP-12 the operations department inappropriately assumed that a ± 1 percent uncertainty existed and that; therefore, the reactor could be operated at up to 101 percent with a ± 1 percent uncertainty and still be within the appropriate design basis. The questions to determine if an USQ evaluation was needed, were all answered "no." However, the question "Does the item involve a change to the facility as described in the SAR?" should have been answered "yes." Therefore, an evaluation to determine if an USQ existed was required to be performed. The failure to appropriately evaluate this procedure revision, resulted in allowing the facility to operate up to 101 percent of maximum licensed thermal power. Initial review to determine if the facility had operated above 100 percent utilizing this operating practice did not identify any other instances. This issue is considered an unresolved item (50-255/96002-02(DRP)) pending further review by the licensee to determine if an USQ existed and the facility was operated outside the design basis.

1.3 Minor Dilution of the Primary Coolant System (PCS)

On February 14, 1996, during the performance of primary coolant system (PCS) leak rate testing, the operating shift noted that the volume control tank (VCT) level was rising with no water additions being made to the PCS. The PCS leakrate data indicated leakage into the PCS at a rate of approximately 4.8 gallons per hour (-0.0767 gpm).

Initial troubleshooting suggested that the leakage was primary makeup water (PMW) leaking past the boric acid blender outlet and the PMW control valves. Manual isolation valves were shut and the PMW pumps were stopped to secure the uncontrolled dilution. Further troubleshooting noted that the dilution still existed whenever a PMW pump was running. The in-leakage was subsequently attributed to valve MV-CVC2047, which was found to be partially opened. This allowed PMW to flow into the delithiating demineralizers, T-51A and T-51B and into the letdown system which returns back to the PCS. This flow path was created when a temporary change to the procedure was initiated on February 14, 1996, due to potential degradation of valve, MV-CVC2027. The in-leakage was

secured when MV-CVC2047 was closed and a work order was initiated to check the valve and remote operator for proper closing, and repair as necessary.

The licensee did an excellent job of identifying the leakage and ultimately locating the source of the in-leakage that was contributing to the uncontrolled dilution.

1.4 Chemical Spill Event

Due to poor plant material condition a significant chemical spill occurred which had the potential for personnel injury. This was the third spill from this system piping since December 1995.

On February 20, 1996, during a regeneration of the A train demineralizer, several gallons of a caustic and acid batch solution from the makeup demineralizer chemical skid, located on the second floor of the feed water purity building, spilled onto the ground floor. The spill came from an overhead drain pipe, previously identified to be corroded through-wall. The drain pipe was the normal effluent path from the chemical addition skid to two adjacent makeup demineralizer trains.

Since no one was in the immediate vicinity when the spill occurred, no personal injury occurred. However, the inspectors noted that auxiliary operators (AOs) had identified this problem to management prior to the event occurring, but no immediate action was taken.

1.5 Unmonitored Discharge to the Environment

On February 29, 1996, due to a leaking drain valve, an estimated 15,000 gallons of dilute sulfuric acid leaked from the waste neutralizer tank. Inventory which was released at a rate of one and a half gallons per minute, went unnoticed from February 20 until February 28, 1996 due to an unreliable tank level indicator. Maintenance had attempted to repair the level indicator, but due to inadequate post maintenance testing, failed to recognize the instrument was still inaccurate. The tank empties into a drain, which is routed to the lake mixing basin along with other runoff that was directed to the mixing basin. The licensee determined that no discharge limits were violated.

The tank was drained and the drain valve disassembled. A slushy frozen white substance was found between the seat and the diaphragm. The drain line and drain line body was heat traced, but the valve bonnet was exposed. It was postulated that local chemical precipitation and freezing caused interference with the diaphragm, preventing positive valve shutoff.

1.6 Cooling Tower Pump Trip

On March 6, 1996, the "B" cooling tower pump (P-39B) tripped while the plant was on line at full power. Operators immediately initiated an emergency power reduction. The power reduction was initiated to reduce reactor power and turbine power to maintain turbine back pressure and condenser vacuum within limits. Reactor power was reduced at a rate of 200 percent per hour to

approximately 53 percent. Condenser vacuum was maintained above 25" Hg during the down power evolution. In reviewing the event, the inspectors noted that the operating crew did an excellent job of coordinating activities and reducing reactor power in a timely manner. Overall, the plant responded very well with feedwater control and the turbine control systems functioning appropriately during the power reduction. The inspectors did note; however, that the operators had to put the turbine control (DEH) system in manual to control the turbine reduction. The licensee is in the process of determining if there is a response problem with the DEH system.

During subsequent followup, systems and reactor engineering provided immediate support to the operating shift and responded to the site. Initial troubleshooting identified the pump tripped on low cooling water flow to the pump seal lube oil. The auxiliary operator was in the process of tagging out the service water filter (F-13A) when the pump tripped. The auxiliary operator also observed that the associated filter went into backwash at the same time as the pump trip. Initial review noted that although the removal of the filter could have affected the service water flow, the backup system should have assured adequate flow to the pump seal. The service water filter is of a duplex design that should not have affected cooling flow. Further troubleshooting found that the check valve, CW589, between the service water system and the pump discharge might not have isolated the service water system. The failure of the CW589, along with inadequate flow balancing at the lower system pressure could have resulted in low seal cooling flow.

In reviewing the cooling tower pump trip, the inspectors noted that two previous cooling tower pump trips had occurred within the last four years. These trips were associated with faulty seal cooling water flow switches. In this instance, the flow switch operated as intended to trip the pump on low cooling water flow.

The plant was returned to full power on March 9, 1996, following additional troubleshooting and flow balance adjustments.

2.0 MAINTENANCE

NRC Inspection Procedures 62703 and 61726 were used to perform an inspection of maintenance and testing activities.

2.1 Maintenance Activities

Portions of the following maintenance activities were observed or reviewed:

- Meggering Of The P-54 Containment Spray Pump
- Replacement Of Temperature Transmitters Inside The C-105 Panel For The "A" Evaporator
- Boric Acid Batch Tank Outlet Relief Valve Heat Trace Installation
- Repairs To Auxiliary Feed Pump Inboard Seal On P-8C

2.2 Surveillance Activities

Portions of the following surveillance activities were observed or reviewed:

- QO-16, "Inservice Test Procedure - Containment Spray Pump
- MI-5A, "Containment High Pressure Switches Test"
- MI-39, "Auxiliary Feedwater Pump Actuation System Logic Test"
- MO-38, "Auxiliary Feedwater Pumps - Inservice Test Procedure"

3.0 ENGINEERING

NRC Inspection Procedure 37551 was used to perform an inspection of engineering activities.

3.1 Safeguards Bus Cable Replacement

The inspectors reviewed the licensee's engineering evaluation of cable supports for the safeguards bus cable re-route through the turbine building. Five supports inside the plant and three supports outside the plant required modifications to ensure their adequacy to support the additional cable. The inspectors observations of accessible supports verified that those supports had been modified as detailed in the engineering evaluation.

The inspectors reviewed engineering analysis package SC-96-003, for the modification re-routing cables A1203/A12-X02/1 through the turbine building vice under the turbine building. Reviews included condition report, C-PAL-96-0055, the 10CFR50.59 safety review report and the 10CFR50, Appendix R review. The inspector noted that the Updated Final Safety Analysis Report (UFSAR) had not yet been processed to reflect the modified condition. No discrepancies were noted during the reviews.

Failure analysis is being performed at both the licensee's and the cable manufacturer's test laboratories. The licensee informed the inspectors that additional analyses are being conducted at Detroit Edison and Ontario Hydro facilities. The root cause of the cable failure has not been determined.

3.2 Generic Letter 89-10 Program Implementation

The focus of this inspection was to evaluate the process for qualifying the design-basis capability of MOVs and closure of GL 89-10. The inspection concentrated on evaluating MOVs that were tested under static or low differential pressure (dP) conditions. A valve sample that included several program closure methods used by Palisades was selected to verify design basis capability. The inspectors reviewed design basis documents, thrust calculations, test packages, and engineering evaluations for the following MOVs:

MO-1042A	PORV Block Valve
MO-2140	Boric Acid Pump Feed Stop Valve
MO-3015	Shutdown Cooling Stop Valve
MO-3066	High Pressure Safety Injection Stop Valve
MO-3080	Hot Leg Injection
MO-3089	Low Pressure Safety Injection

3.2.1 Program Scope Changes

Since the Part 2 inspection, eight auxiliary feedwater (AFW) valves were appropriately removed from the program. These valves were part of the automatic isolation feature of the AFW "Feed Only Good Generator (FOGG)" system that was disabled. Isolation of a faulted steam generated is now accomplished via alternate means. The valves' electrical breakers were racked out and the valves were manually chained locked. No credit was taken in Palisades design basis for automatic operation of these valves nor were the valves used for any design basis accident mitigating function.

With the changes, the program scope now consisted of 30 MOVs (15 gate valves and 15 globe valves). All valves were statically tested and 19 were dynamically tested.

3.2.2 Design Basis Capability Verification

Palisades satisfactorily established the design basis capability of all program MOVs including those that had not been tested at or near design basis conditions. The standard industry thrust equation was used to determine gate valve design basis thrust requirements. The thrust calculations applied valve factors (VFs) derived from dynamic testing, or for gate valves that were not dynamically tested, from analysis of industry test data. A stem friction coefficient of 0.20 was used for determination of actuator output thrust capability, and a 10 percent margin for load sensitive behavior and valve degradation was included for valves that were controlled by the torque switch. Stem friction coefficient and load sensitive behavior values were sufficiently verified using static and dynamic plant test data. Minimum thrust requirements for setting of actuator torque switches were appropriately adjusted to account for diagnostic equipment inaccuracy and torque switch repeatability.

3.2.3 Inadequate Valve Factor Matches

The inspectors noted a lack of rigor in obtaining good valve factor (VF) matches for two gate valve groups that were not dynamically tested at Palisades. In some instances, valve comparisons were made with dissimilar disc design, size, and pressure class. For example, the PORV block valves (MO-1042A and MO-1043A), were 4" Edwards Equiwedge gate valves (1550#) matched with industry data from 4" Anchor Darling (1500#) double-disc gate valves with a VF of 0.60.

Based on the inspectors' concerns, the licensee contacted other facilities and obtained additional VF information, including information from industry

sponsored testing of a similar 2½" Edwards Equiwedge gate valve. After further review, Palisades determined that a VF of 0.68 was more appropriate for the PORV block valves. The inspectors considered the current PORV block valve setup to be adequate for program closure based on valve margin that could support VFs between 0.71 and 0.76 and the licensee's agreement to continue their efforts to review applicable data as it became available.

Based on the VFs applied, the available thrust margin, and the licensee's willingness to continue their efforts to review applicable data, the inspectors considered the settings for all of Palisades' non-dynamically tested gate valves to be adequate for program closure.

3.2.4 Omission of Valve Degradation Margin

MOV setup methodology did not include a 5 percent stem lube and valve degradation margin when calculating open thrust requirements. The licensee did account for this 5 percent degradation for all valves in the close direction. Although full actuator capability would be available to open the valve, degradation may still occur and potentially cause an operability concern for an MOV that has marginal open capability. Licensee personnel agreed to revise the requirements to include this margin. No concerns were noted when the 5 percent margin was appropriately added.

3.2.5 Low Thrust Margins

The inspectors noted that the high pressure injection stop valves (MO-3062, 3064, 3066, and 3068) were marginal in the open direction because of high apparent open VFs derived from the dynamic test results. The most marginal valve, MO-3066, had a calculated design thrust margin of -7 percent, when assuming a stem friction coefficient of 0.20. The high apparent open VFs were caused, in part, by the large diagnostic equipment uncertainties that needed to be applied to the open VOTES thrust measurements. To show adequate thrust margin for MO-3066, the licensee relied on the 0.16 stem friction coefficient measured during the dynamic test.

In response to the inspectors' concerns, the licensee conducted an additional review of the design-basis dP designated for these MOVs, and determined that a simple change to an operating procedure would allow the dP to be reduced from 2556 psid to 1784 psid. This, in turn, improved MO-3066's open thrust margin (assuming a stem friction coefficient of 0.20) to 21 percent. The licensee also intended to dynamically retest these MOVs at the next opportunity, in an effort to obtain more accurate valve factor data. Based on the licensee's proposed margin improvement plan for these valves, the inspectors' margin concerns were resolved.

3.2.6 Misapplication of Industry Test Data

The inspectors determined that Palisades personnel did not verify the method used to measure disc diameters of industry tested MOVs when determining VFs. This resulted in incorrectly applied VFs for four low pressure safety injection (LPSI) valves. Because Palisades' program included thrust calculations that used a mixture of mean seat and orifice diameters, nonconservative VFs could be inappropriately applied if the tested MOV's derived VF was calculated using a mean seat based disc area term, and applied

to another MOV that used an orifice based disc area term. New VFs were calculated using the correct orifice diameter and resulted in a VF increase of 0.75 to 0.85. However, this increase did not create any operability concerns, because of each valve's available thrust margin. The licensee documented this error in condition report C-PAL-96-0040. The inspectors considered the issue resolved.

3.2.7 Extrapolation of Open Torque Measurements

The licensee did not extrapolate open torque measurements when dynamic tests were conducted at less than design basis dP conditions. This was considered a program weakness since this evaluation error could potentially cause an inoperable MOV to remain undiscovered. Licensee personnel agreed that this evaluation was needed, and revised all torque margin assessments that had been obtained from the dynamic test program. The reduction in torque margins did not result in any operability concerns. The licensee agreed to revise dynamic test evaluation methods to ensure that future tests were evaluated properly.

3.2.8 Inoperable MOVs After A Postulated Appendix R Fire Scenario

Twenty MOVs required for Appendix R safe shutdown have actuators sized and physically wired such that a spurious signal, without the benefit of protective devices in the circuit, could result in physical damage to the valve. This condition, as described in NRC Information Notice (IN) 92-18, could result in an unrecoverable scenario during a postulated Appendix R fire. The 20 valves are in the main steam, chemical and volume control, high pressure safety injection, and low pressure safety injection systems.

The licensee's initial March 1992 response to IN 92-18 assumed that the valve operator may be damaged to the point where it could no longer function, but did not consider the possibility that physical damage to the valve itself could be significant enough to preclude manual repositioning of the valves.

An Appendix R re-analysis in the fall of 1994 identified that MOV program data were necessary to adequately address the IN. When weak link and valve actuator thrust data became available in September 1995, eight LPSI valves were subject to valve physical damage as a result of postulated hot shorts in the control circuits as described in IN 92-18. MOV engineering further reviewed the analysis and identified an additional 12 susceptible valves due to factors not considered by Appendix R engineering. The 1994 analysis was revised and included the one-time stress allowable, motor stall torque and stall thrust values based on 100 percent voltage and the actual measured valve coefficient of friction in place of the operator capability thrust values used in the initial calculation.

Interim corrective actions consisted of hourly fire tours and were credited as a compensatory measure to ensure that the probability of a fire and subsequent fire damage to an MOV control circuit was sufficiently low. The fire tours will continue until permanent corrective actions are complete. This issue is considered an unresolved item (50-255/96002-03(DRS)).

3.2.9 Periodic Verification

Plans for periodic verification (PV) of MOVs were acceptable for program closure; however, this issue will be reviewed further under the guidance of a

forthcoming Generic Letter. Palisades planned to statically diagnostically test all program valves every third refueling outage or every five years as part of a comprehensive preventive maintenance program. Additionally, dynamic diagnostic tests were planned for all practicable-to-test program valves every third outage or every five years if the MOV does not demonstrate a 25 percent margin after including all appropriate uncertainties. If tested margin is greater than 25 percent, then dynamic testing will occur every fifth refueling outage or every eight years.

The NRC staff is preparing a GL on the PV of MOV design basis capability and will review the PV program in greater detail following issuance. Palisades should review its program and consider the benefits (such as identification of decreased thrust output and increased thrust requirements) and potential adverse effects (such as accelerated aging or valve damage) when determining appropriate PV testing for each MOV.

3.2.10 Appropriate Post-Maintenance Testing (PMT) Guidelines

Guidelines for post-maintenance testing of MOVs were considered appropriate for program closeout. The guidelines required the performance of static diagnostic testing to demonstrate that each MOV remains capable of operating under design basis conditions following packing replacement or adjustment or after valve or operator maintenance. Additionally, dynamic diagnostic testing is required following valve replacement or valve internal work that may affect thrust requirements.

3.2.11 Pressure Locking and Thermal Binding (PL/TB)

The licensee adequately addressed PL/TB concerns in response to GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." Nine valves were documented as potentially susceptible to PL/TB and were considered operable for the short-term based on analytical calculations or engineering judgement. Long-term corrective actions were not finalized at the time of the inspection. The licensee was considering modifications to four valves to alleviate PL concerns. The area of PL/TB will be reevaluated in the future under the guidance of GL 95-07.

3.2.12 MOV Trending and Corrective Actions

The trending program appeared capable of adequately tracking and evaluating data to maintain MOV design-basis capability. MOV Trend Summary Reports will be generated on a semiannual basis to track and trend MOV design changes, maintenance histories, test results, failures, and corrective actions. This included trending MOV diagnostic performance parameters obtained during testing activities. Adverse and non-adverse trends will be analyzed to determine if corrective action is warranted.

A review of the first Trend Summary Report (July through December 1995) found that, overall, assessments and subsequent corrective actions were handled appropriately.

3.2.13 Effective Self-Assessments

Self-assessments were considered a strength to the overall GL 89-10 program. Since the Part 2 inspection, Palisades completed three MOV program

self-assessments that contributed to successful outage testing and to timely GL 89-10 program completion. The assessments provided good technical findings and, overall, the plant responded with appropriate corrective actions. The use of reviewers with technical MOV background resulted in a critical program review.

4.0 PLANT SUPPORT

NRC Inspection Procedures 83750 and 86750 were used to conduct an inspection of plant support activities. The licensee's performance in the area of radiation protection continued to be adequate.

4.1 Radiation Worker (Radworker) Performance

NRC inspection reports 50-255/95008(DRP) and 50-255/95011(DRP) documented inspector observations of poor radworker practices during the last refueling outage. During this inspection, the inspectors reviewed the licensee's plans for improving overall radworker performance and conducted plant tours in order to evaluate actual radworker performance in radiologically controlled areas. The inspectors observed excellent radworker performance during the conduct of some activities; however, other inspector observations indicated that the licensee's expectations still have not been fully communicated to, and implemented by, the station work force.

4.1.1 Examples of Excellent Radworker Performance

The inspectors observed a significant portion of the loading of barrels of radioactive waste (radwaste) into a transport container for shipment to a burial site. During each stage of the evolution, including the attachment of a lifting device to each barrel, surveying for external contamination, and loading the barrels into the transport container, the radworkers employed excellent radiation exposure minimization techniques that maintained the total dose for the job As Low As Reasonably Achievable (ALARA). Each radworker minimized the time that they were near the barrels of solidified radioactive waste. Each radworker maintained a reasonable distance from the barrels when not required to be near them for the performance of their respective duties. Also, when available, the radworkers used the natural shielding provided by the walls of the transport container to reduce their radiation exposure. All of these dose saving techniques resulted in the job being completed for about two-thirds of the dose usually expended for this evolution.

4.1.2 Examples of Continued Poor Radworker Performance

The inspectors observed two work activities that indicated the licensee continues to be challenged by poor radworker practices and has not taken a proactive approach to improving overall radworker performance. In both instances, the licensee failed to take significant action during the job evolutions to address the poor practices observed. In one case, the inspectors noted that numerous individuals were observing repairs on auxiliary feedwater pump P-8C, while standing in an area with general area radiation exposure rates of 10 to 40 millirem per hour. After the job had been completed, the licensee discovered that there had been approximately 80 entries under the radiation work permit (RWP) for that

job and other, associated general RWPs. The inspectors expressed the concern that during the repair activities observers in the area were not challenged regarding their presence in the area and whether they actually were required to be in the area during the repairs and testing.

During the second observation, the inspectors witnessed a minor entry into a contaminated area to retrieve an air monitor and a length of hose. One of the radworkers, after crossing into the contaminated area, and who was fully dressed in protective clothing (PCs), wiped his face on the sleeve of his PCs. Although the radworker had just crossed over the stepoff pad and had not yet handled any contaminated, or potentially contaminated, objects, this example shows poor awareness on that individual's part regarding management expectations of radworker practices and personnel contamination control. The inspectors expressed their concern for: (1) the radworker's poor practice with regard to personnel contamination control while dressed out in PCs, and (2) the failure of the radiation protection tech stationed outside the contaminated zone and less than 2 meters from the radworker to observe and correct the poor practice. After the radworker exited the contaminated area, the inspectors questioned him regarding the observed practice. The radworker commented that he was not aware that he had wiped his face on the sleeve of his PCs. A post-exit survey indicated that the radworker's face had not become contaminated.

4.2 Radioactive Waste (Radwaste) Handling System

The inspection included a review of the licensee's radwaste volume reduction system (VRS), which employs heated asphalt to remove residual moisture from evaporator condensates during the packaging process. The inspectors reviewed two temporary modifications to the VRS. The modifications involved removing two sections of hard piping from the system, which had become clogged with dried condensates from the radwaste evaporators. The sections removed involved a significant length of piping, which was replaced with rubber hoses. The longest lengths removed during the temporary modifications were approximately 25 meters each. In one modification, the hose used to replace the hard piping was laid across a boiler used to produce steam for heating the asphalt, potentially compromising the integrity of the hose. The inspectors expressed their concern that, should the hose fail to maintain its integrity, a leak could contaminate normally clean areas of the auxiliary building, including the instrument facility of the radiological and chemistry services department, over which the hose traverses. The licensee is evaluating its options regarding the future use of the VRS and may decide to abandon the system in favor of contracting its radwaste volume reduction activities.

5.0 REVIEW OF UPDATED FINAL HAZARDS SUMMARY REPORT

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Hazards Summary Report (UFHSR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFHSR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable

portions of the UFHSR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

6.0 PERSONS CONTACTED AND MANAGEMENT MEETINGS

The inspectors contacted various licensee operations, maintenance, engineering, and plant support personnel throughout the inspection period. Senior personnel are listed below.

At the conclusion of the inspection, the inspectors met with licensee representatives (denoted by *) and summarized the scope and findings of the inspection activities. The licensee did not identify any of the documents or processes reviewed by the inspectors are proprietary.

Consumers Power Company (CPCo)

R. A. Fenech, Vice President, Nuclear Operations
#* T. J. Palmisano, Plant General Manager
#* K. P. Powers, Nuclear Services General Manager
* G. B. Szczotka, Nuclear Performance Assessment Manager
* H. L. Linsinbigler, Design Engineering Manager
#* D. W. Smedley, Licensing Manager
D. W. Rogers, Operations Manager
* S. Y. Wawro, Planning & Scheduling Manager
R. B. Kasper, Maintenance & Construction Manager
* K. M. Haas, Training Manager
* C. R. Ritt, Administration Manager
R. J. Gerling, Nuclear Fuels Manager
* D. P. Fadel, System Engineering Manager
* D. G. Malone, Shift Operations Supervisor
* D. J. Malone, Chemical & Radiation Protection Services Manager
J. P. Pomaranski, Deputy Maintenance & Construction Manager
* R. A. Vincent, Licensing Supervisor
#* R. E. McCaleb, NPAD Site Assessment Supervisor
R. A. Gambrill, MOV Program Manager
D. E. Gustafson, Engineering Programs
R. L. Scudder, Engineering Programs Supervisor

U. S. Nuclear Regulatory Commission (NRC)

J. M. Jacobson, Engineering Branch Chief
#* M. E. Parker, Senior Resident Inspector
#* P. F. Prescott, Resident Inspector
S. D. Burgess, DRS Inspector
A. Dunlop, DRS Inspector
J. G. Guzman, DRS Inspector
J. H. Neisler, DRS Inspector
J. L. Cameron, DRS Inspector
M. Holbrook, NRC Consultant, INEL

* Denotes those attending the exit meeting on March 19, 1996.
# Denotes those attending the MOV exit meeting on January 12, 1996.