ENCLOSURE

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REGION IV

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Facility:	Diablo Canyon Nuclear Power Plant, Units 1 and 2
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ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Diablo Canyon Nuclear Power Plant, Units 1 and 2
NRC Inspection Report No. 50-275/99-03; 50-323/99-03

This inspection evaluated aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection.

Operations

- The planning, preparations, and execution of the two draindowns of the Unit 1 reactor to reduced inventory conditions were generally conducted in a conservative manner. Licensee contingencies and compensatory actions were appropriate to the circumstances (Section O1.2).

- In Mode 6, while pressurizing the primary relief tank with nitrogen during the draindown to midloop, operators did not have a full understanding of its effect on reactor vessel level. As a result, reactor vessel level dropped approximately 2 feet in an uncontrolled manner, and water flowed into the steam generator tubes. No procedural limits were exceeded (Section O1.2).

- The first example of a noncited violation of Technical Specification 6.8.1.a. for failure to properly implement a procedure, involved the draindown to midloop (AR A0479457). The "Mid Loop Trouble" alarm was not enabled to alert operators of reactor vessel refueling level high or low, as required (Section O1.2).

- With the exception of minor performance and communications problems, which occurred during performance of the initial steps of refueling, all parties involved in the fuel load performed well. Performance during core alterations was improved in that procedure and performance concerns identified in Refueling Outage 2R8 were corrected for Refueling Outage 1R9 (Section O1.3).

- Clearance performance during Refueling Outage 1R9 improved as compared to previous outages. A sampling of clearances that the inspectors examined revealed only one minor error. In addition, the licensee identified fewer significant clearance errors than during Refueling Outage 2R8, indicating that corrective actions have improved clearance performance (Section O1.4).

- Operators failed to revise the risk assessment of performing the residual heat removal (RHR) system flush during power operation when they elected to include removal of the boric acid storage tanks from service. Operators understood that the boric acid storage tanks were of low risk significance and, because of weak knowledge of the on-line maintenance risk assessment procedure, believed that a revision of the risk assessment was unnecessary. Subsequent evaluation of the risk associated with this activity confirmed the risk was low. (Section O4.1).

- Operating procedures were not conservative with respect to monitoring spent fuel pool temperature since increased temperature monitoring was not required with a full core offload in the spent fuel pool. Operators continued to monitor the Unit 1 spent fuel pool temperature every 12 hours. As a result, following an inadvertent trip of Spent Fuel Cooling Pump 1-2, the pump trip went undetected for 4 hours until a spent fuel pool high temperature annunciator alarmed (Section M1.3).

Maintenance

- The first example of a noncited violation of Technical Specification 6.8.1.a. for failure to properly preplan maintenance was identified during the initial draindown of the Unit 1 reactor to midloop (AR A0476823). Isolation of the nitrogen overpressure for the primary relief tank resulted in reactor vessel level perturbations (Section O1.2).

- The second example of a noncited violation of Technical Specification 6.8.1.a. for not properly preplanning maintenance, which was associated with replacing a relay that provided Phase A containment isolation capability (AR A0478430), was identified. The relay was removed without adequate precautions or consideration for the effect on plant equipment. As a result, the operating spent fuel pool cooling pump tripped from service without operator knowledge (Section M1.3).

- A noncited violation of Technical Specification 6.8.1a. for failing to provide a procedure appropriate to the circumstances (AR A0479274) was identified. In this instance, the procedure used to restore the 500 kV offsite power source provided vague guidance for positioning the main turbine protective trip switches. In addition, lack of a questioning attitude on the part of operators restoring the 500 kV power contributed to the trip signal, partial loss of offsite power, and inadvertent diesel engine generator (DEG) start. Operator response in restoring shutdown and spent fuel pool cooling following the loss of 500 kV power was good (Section M1.4).

- Following the failure of DEG 1-1 to reach rated voltage within its acceptance criteria, troubleshooting to determine the cause of the problem was generally thorough and identified a suspect voltage regulator. Troubleshooting appropriately considered vendor recommendations and collected data and the number and frequency of tests exceeded requirements (Section M1.5).

Engineering

- The prompt operability assessment associated with fibrous material in fire stops in containment in both units, while technically sound, was not timely given the potential safety significance of inoperable containment recirculation sumps. The operability question of the containment recirculation sumps was identified in October 1998. However, the prompt operability assessment was not completed until February 1999. The inspectors identified a deficiency in the operability process, specifically, the "issue needing validation to determine the impact on operability" portion. The licensee had missed two opportunities to perform a prompt operability assessment in December 1998 when forced outages had occurred in each unit (Section E1.1).

- On January 14, 1998, a violation of 10 CFR 50.59 resulted because the licensee implemented a design change and failed to submit a license amendment for a change to the facility that involved an unreviewed safety question. The NRC, however, is exercising enforcement discretion in accordance with Section VII.B.6 of the enforcement policy and is refraining from issuing a Notice of Violation. The licensee changed the configuration of the 230 kV offsite power source from dependence on Morro Bay for operability to dependence on load tap changing transformers and capacitor banks. Corrective actions for previous 10 CFR 50.59 violations sufficiently addressed this issue. The design change improved the reliability of the 230 kV system (Section E1.2).

Plant Support

- The second example of a noncited violation of Technical Specification 6.8.1.a for failure to follow procedure resulted when chemists failed to sample the chemical and volume control system demineralizer prior to placing it in service (NCR N0002084). This error resulted in a significant chloride intrusion into the reactor coolant system and caused the Equipment Control Guideline limit to be exceeded. In addition, the controls for the purchase, control, and dedication of resins for nonsafety-related applications were deficient. The licensee performed a detailed root cause analysis and corrective actions addressed the issues appropriately (Section R1.1).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. Unit 1 began coasting down for the end of the fuel cycle on February 3, 1999, and was at 93 percent power on February 7. On February 7, Unit 1 was shut down to commence Refueling Outage 1R9. Unit 1 was in Mode 5 (Cold Shutdown) at the end of this inspection period.

Unit 2 operated at essentially 100 percent power during this inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors visited the control room and toured the plant on a frequent basis when on site, including periodic backshift inspections. In general, the performance of plant operators reflected a focus on safety, evidenced by self- and peer-checking. Operator use of three-way communications continued to improve, and operator responses to alarms were usually observed to be prompt and appropriate to the circumstances.

O1.2 Midloop Operations (Unit 1)

a. Inspection Scope (71707)

The inspectors observed the licensee's performance related to draining the Unit 1 reactor coolant system to reduced inventory. This inspection included: (1) review of training, procedures, and safety assessments, (2) plant tours, (3) interviews, and (4) observation of on-shift personnel.

b. Observations and Findings

General

During Refueling Outage 1R9, the licensee drained the reactor coolant system to midloop on two occasions to install and remove reactor coolant loop nozzle dams, which supported steam generator eddy current inspection. The midloop operations were performed with fuel in the reactor vessel. Most significantly, the steam generator nozzle dams were installed shortly after the Unit 1 reactor shutdown, when the decay heat load was high. The inspectors determined that this was a risk significant configuration.

Planning and Preparations

Technical Specifications required only one DEG, one source of offsite power, and one RHR pump to be operable with the plant in Mode 5 (cold shutdown). However, the licensee determined that additional safety systems would be made available because of the increased risk when in reduced inventory. Procedures OP A-2:II "Reactor Vessel - Draining the Reactor Coolant System to the Vessel Flange - with Fuel in the Vessel," Revision 20, and OP A-2:III, "Reactor Vessel - Draining to Half Loop/Half Loop Operations with Fuel in the Vessel," Revision 20, required many systems in excess of those required by the Technical Specifications to be available (e.g., two sources of offsite power, two DEGs, two RHR pumps, and containment closure). Other contingencies included stationing operators at the intake structure near the auxiliary saltwater pumps and in the auxiliary building near the RHR pumps to recover these important systems, if necessary.

In addition, the licensee staged a senior reactor operator at the radiological control access point to screen work to ensure that midloop operations would not be impacted. The outage safety plan for Refueling Outage 1R9 also required operators to receive simulator training on reduced inventory operations, including the offsite power sources to be protected, so work that could impact midloop operations would not be performed. The inspectors concluded that the planning, preparations, and contingencies showed appropriate sensitivity to effective implementation of refueling activities. On February 10, the inspectors independently verified that these contingencies were satisfactorily in place prior to commencement of the reactor coolant system draindown.

Hot Midloop

On February 12, 1999, the licensee commenced the draindown to midloop with a high decay heat load. During this draindown, the narrow-range reactor vessel refueling level indication system (RVRLIS) diverged from the wide-range RVRLIS system several times by more than 4 inches, such that operators had to stop the draindown and direct technical maintenance personnel to fill and vent the RVRLIS detectors.

During one such divergence, operators checked the nitrogen overpressure of the primary relief tank. Procedure OP A-2:II required the pressure to be set at 3 psig; however, operators discovered that the pressure read 0 psig and inspected the nitrogen supply lineup. Operators determined that the nitrogen supply was inadvertently isolated, as specified in Clearance 60376, for maintenance unrelated to the midloop operations. Operators wrote an action request (AR) to enter this item into the corrective action program.

Following identification that the nitrogen was isolated, operators quickly cleared the tags and opened the nitrogen system isolation valves. Restoring the nitrogen overpressure to the primary relief tank resulted in a sudden and uncontrolled level drop of 2 feet. The level decrease stopped at 111 feet, which was significantly above midloop (107 feet, 8 inches) but was neither controlled nor understood by the operators. The manager in charge halted the draindown to midloop until an investigation was completed and the cause of the level perturbations and sudden drop was understood. The licensee

determined that the level dropped because the nitrogen overpressure pushed water into the empty steam generator tubes.

Procedure OP A-2:II, Section 4.4, required operators to review the clearance and jumper logs to identify any work that could impact reduced inventory operations, prior to commencing the draindown. Since this step had been previously signed off as completed satisfactorily, the inspectors were concerned about the thoroughness of this review. The licensee determined that Clearance 60376 had not yet been listed as an active clearance when operators reviewed the clearance log. Consequently, the licensee reverified each of the prerequisites, including any clearances that were in the process of being hung but were not yet active, and recommenced the draindown.

Because Clearance 60376 was initiated without reviewing its impact on RVRLIS and midloop operations, this maintenance activity was not properly reviewed for the circumstances. This licensee-identified deficiency is the first example of a violation of Technical Specifications 6.8.1.a for failure to properly preplan maintenance. However, this Severity Level IV violation is being treated as a noncited violation, consistent with Appendix C of the Enforcement Policy. This violation is in the corrective action program as AR A0476823 (50-275/99003-01).

Following resolution of the RVRLIS issues, the licensee completed the draindown. The inspectors noted that the rest of the evolution, including installation of nozzle dams and refill of the reactor coolant loops, was completed satisfactorily and in a conservative manner.

Second Midloop

On March 4, operators commenced a second draindown to midloop to remove the steam generator nozzle dams. The licensee instituted similar contingencies and preparations as with the hot midloop. Decay heat load was significantly less than the earlier midloop condition in that one-third of the fuel had not been irradiated following core reload and the reactor had been shut down for approximately 1 month. Therefore, engineers determined that the second draindown to midloop had less risk significance than the first. The inspectors verified that a sampling of the prerequisites had been satisfactorily completed.

During the draindown, with RVRLIS level stabilized at 109 feet, the inspectors questioned whether operators had enabled the "Mid Loop Trouble" alarm. Procedure OP A-2:III, step 6.1.1, required the operators to verify that the narrow range RVRLIS level alarms had been enabled. Operators had previously enabled both the "RVRLIS High/Low" and the "Mid Loop Trouble" alarms. These annunciators provided operators with warnings to prevent RVRLIS level from being too high such that it would impact personnel removing nozzle dams or too low such that vortexing of the reactor water inventory could impact the operating RHR system. However, prior to commencement of draindown, operators inadvertently disabled the "Mid Loop Trouble" alarm by setting up operating bands using the plant process computer select function.

Procedure OP A-2:III, Section 4.5.1, permitted operators to establish operating bands using the plant process computer select function in addition to enabling the normal-range RVRLIS level alarms. Operators were not aware that using the plant process computer select function could effect the narrow-range RVRLIS system.

Upon the inspectors' questioning, operators determined that Procedure OP A-2:III, Step 6.1.1, had not been fully implemented. The shift foreman initiated AR A0479457 to enter this item into the corrective action system, and the control operator restored the "Mid Loop Trouble" alarm to operation. The draindown and refill of the reactor coolant loops was completed without further incident. The failure to enable the "Mid Loop Trouble" alarm prior to draindown is the first example of a violation of Technical Specification 6.8.1.a for failure to follow procedure. However, this Severity Level IV violation is being treated as a noncited violation, consistent with Appendix C of the Enforcement Policy. This violation is in the corrective action program as AR A0479457 (50-275/99003-02).

c. Conclusions

The planning, preparations, and execution of the two draindowns of the Unit 1 reactor coolant system to midloop were generally conducted in a conservative manner. Licensee contingencies and compensatory actions were appropriate to the circumstances.

The first example of a noncited violation of Technical Specification 6.8.1.a. for failure to properly preplan maintenance was identified during the initial draindown of the Unit 1 reactor to midloop (AR A0476823). Isolation of the nitrogen overpressure for the primary relief tank resulted in reactor vessel level perturbations. In Mode 6, while pressurizing the primary relief tank with nitrogen during the draindown to midloop, operators did not have a full understanding of its effect on reactor vessel level. As a result, reactor vessel level dropped approximately 2 feet in an uncontrolled manner, and water flowed into the steam generator tubes. No procedural limits were exceeded.

The first example of a noncited violation of Technical Specification 6.8.1.a. for failure to properly implement a procedure, involved the draindown to midloop (AR A0479457). The "Mid Loop Trouble" alarm was not enabled to alert operators of reactor vessel refueling level high or low, as required.

O1.3 Refueling Activities

a. Inspection Scope (71707)

On February 27, 1999, the inspectors observed refueling activities in the control room, fuel building, and containment. These activities included handling and movement of the fuel assemblies from the spent fuel pool to the upender and from the upender to the final core location, control room monitoring of required parameters, reactor engineering calculations of inverse count rate ratio, and monitoring of fuel location for accountability

requirements. The inspectors reviewed Procedures OP B-8DS2, "Core Loading," Revision 21, and PEP R-8DS2, "Core Loading Sequence," Revision 1, which contained the procedure requirements for these activities.

b. Observations and Findings

Ultrasonic inspection of the reactor pressure vessel outlet nozzles was required to be complete prior to beginning fuel load. Ultrasonic inspection of the reactor pressure vessel nozzles was completed several hours ahead of time, which created an opportunity to begin fuel load earlier than scheduled. Lighting, tools, and other equipment and prerequisites for fuel load had not been prestaged. Consequently, the opportunity to start fuel load ahead of time passed. Communication of status, duration, and level of effort to complete these activities was, at times, not clearly communicated. The operations shift foreman appropriately delayed the start of fuel load until prerequisite items were verified to be complete. Senior managers were promptly informed of the communication problem and intervened in a timely manner to alleviate the problem.

During performance of the initial steps of Procedure PEP R-8DS2, Fuel Assembly AA83 was raised out of the spent fuel pool rack prior to unloading Fuel Assembly BB04 from the upender inside of the containment, which was contrary to management expectations. The control room operators immediately recognized this and informed the shift foreman. The shift foreman briefly suspended further core load to make sure that the involved parties understood the management expectations. The inspectors observed a significant portion of the fuel load activities. Other than the minor performance issue described above, the fuel load activities observed by the inspectors were accurately performed in a deliberate manor.

During the last Unit 2 refueling outage, a violation was identified for failing to restore the source range detector high flux at shutdown alarm, as instructed in the core load procedures. Complex instructions and failing to clearly specify the person responsible for completing the actions were identified as contributing causes. For this Unit 1 refueling outage, each action was clearly defined in the procedure, and a specific individual was assigned responsibility for completing the actions. The core loading procedures required that criticality be calculated after the first 13 fuel assemblies are loaded next to their applicable detector and for each fuel assembly added thereafter. Procedure OP B-8DS2, step 5.7.7, states "Criticality is indicated when the inverse count rate ratio approaches zero, and if the straight line determined by the last two Inverse count rate ratios for a responding detector indicates that criticality could occur if the next twelve (12) or less fuel assemblies are loaded." The inspectors observed the reactor engineers verify source range detector count rates and calculate the inverse count rate ratio. Work was satisfactorily accomplished in a timely manner to support fuel load activities.

The inspectors observed the refueling senior reactor operator directing the fuel handling operations in containment. The refueling senior reactor operator maintained good supervision over the activities, maintained communications with the control room and

the personnel in the fuel building, provided clear directions to the crane operator and other observers, verified the correct core location using the fuel movement tracking sheets, monitored the load on the manipulator crane, and confirmed the proper indicating lights and Z-Z tape position.

The inspectors also observed that the foreign material exclusion area controls around the reactor cavity and the spent fuel pool were effective.

c. Conclusions

With the exception of minor performance and communications problems, which occurred during performance of the initial steps of refueling, all parties involved in the fuel load performed generally well. Performance during core alterations was improved, in that procedure and performance concerns identified in Refueling Outage 2R8 were corrected for Refueling Outage 1R9.

O1.4 Clearance Performance

a. Inspection Scope (71707, 92901)

During Unit 2 Refueling Outage 2R8, operators committed a number of significant clearance errors. These errors were discussed in NRC Inspection Report 50-275; 323/98-07, and a violation was issued for several examples of failing to properly implement the clearance procedure. Because of this deficient performance, the inspectors evaluated the clearance order implementation during Refueling Outage 1R9 to determine the effectiveness of the previous corrective actions. The evaluation included walkdowns of several clearances and reviews of licensee-identified issues.

b. Observations and Findings

The inspectors walked down several clearance orders. Of these clearances, the inspectors identified one minor error. On February 12, 1999, the inspectors identified that tags hung for maintenance on breakers associated with the control rod drive motor generator sets were man-on-line tags while the clearance called for caution tags. The breakers were in the correct position, and the tags were hung on the correct components; therefore, personnel and equipment safety were not jeopardized. Personnel initiated an event trend record to document this occurrence, and the operations director issued a shift order to remind operators to verify that the proper type of tag was hanging, as well as the correct component and position. The inspectors noted that the clearances walked down were otherwise satisfactory.

In addition, the inspectors reviewed clearance issues identified on nine ARs. One AR Addressed a man-on-line tag hung on the wrong switch. A second AR discussed an issue that involved several tags being removed with work in progress. The rest of the ARs discussed administrative violations of procedures. In comparison, during Refueling Outage 2R8, the licensee committed eight errors that the inspectors considered significant; each incident involved a lack of tagging protection while work was in progress. The licensee initiated numerous corrective actions as docketed in the

response to NRC Inspection Report 50-275; 323/98-07. The inspectors concluded that, although the licensee achieved significant improvement in performance of clearances because of these corrective actions, further improvement in this area is still necessary.

c. Conclusions

Clearance performance during Refueling Outage 1R9 improved as compared to previous outages. A sampling of clearances that the inspectors examined revealed only one minor error. In addition, the licensee identified fewer significant clearance errors than during Refueling Outage 2R8, indicating that corrective actions have improved clearance performance.

O4 Operator Knowledge and Performance

O4.1 RHR System Flush

a. Inspection Scope (71707)

The inspectors witnessed the flush of the RHR system, including the probablistic risk assessment to support the evolution.

b. Observations and Findings

On February 3, 1999, operators performed a flush of the Unit 1 RHR system in preparation for plant cooldown during upcoming Refueling Outage 1R9. The licensee previously performed this evolution following plant shutdown so that when RHR was initiated, the chemistry of the reactor coolant system would not be adversely affected.

Prior to the flush, the probablistic safety assessment group evaluated the evolution with respect to risk. The RHR system flush required isolation of the RHR system, which rendered the system inoperable for the low pressure safety injection mode of operation and required entry into a 72 hour shutdown action statement for approximately 3 hours total for each train. The engineers noted that removing each RHR train from service to support the flush was not risk significant when evaluated using industry guidelines. The shift foreman reviewed and approved this safety assessment prior to commencement of the RHR system flush.

In preparation for the flush, operators reviewed Procedure OP B-2:V, "RHR - Place in Service During Plant Cooldown," Revision 17, and noted that the procedure required several flow paths to be established simultaneously. Procedure OP B-2:V directed the user to flush water from the RHR system by draining to the radwaste system while filling from the refueling water storage tank. To maintain refueling water storage tank levels, the procedure required the transfer of water from the boric acid storage tanks. In addition, boric acid storage tank inventory would be maintained via the makeup system. Operators determined that control of the evolution would be optimized if fewer flow paths were in service simultaneously. Therefore, the shift foreman determined that boric acid storage tank levels would not be maintained while the evolution was in

progress. The boric acid storage tanks would be refilled once the evolution was completed. Performing Procedure OP B-2:V in this alternative manner required operators to declare the boric acid storage tanks inoperable and enter a 72-hour shutdown action statement.

At the start of the RHR system flush, operators performed a briefing and entered the applicable limiting conditions for operation. Following commencement of the RHR system flush, the inspectors reviewed the approved probablistic safety assessment. The inspectors noted that the probablistic safety assessment included the RHR system as unavailable but did not recognize the inoperability of the boric acid storage tanks. The shift foreman stated that the boric acid storage tanks were not risk significant and need not be evaluated. The shift foreman noted that Procedure AD7.DC6, "On-Line Maintenance Risk Assessment," Revision 2, contained a matrix of the risk significant systems and that the boric acid storage tanks were not included in this matrix. In addition, the boric acid storage tanks were not modeled in the on-line computer program for risk assessment.

However, the inspectors noted that Procedure AD7.DC6, Section 6.5, required a two-step approach to on-line risk assessment. The first step was a probablistic safety assessment using the plant computer and the matrix. In addition, Procedure AD7.DC6, Attachment 9.5, required a deterministic approach to assess safety significance. This section was based on defense-in-depth of the critical safety functions referenced in the emergency operating procedures. Procedure AD7.DC6, Section 6.5, was developed to ensure operators did not cause an inadvertent total loss of safety function and violate the Technical Specifications by removing multiple nonrisk significant systems from service. The inspectors discussed the deterministic assessment required by Procedure AD7.DC6 with the operating crew and identified that the crew was not cognizant of this element of safety assessment. Operators then performed the deterministic review and determined that the configuration of having one RHR pump inoperable coincident with the boric acid storage tanks being inoperable was allowed by procedure and was nonrisk significant.

The inspectors discussed this issue with the Operations Director. The Operations Director evaluated the operator knowledge of Procedure AD7.DC6 and identified that most of the other operating crews were similarly unfamiliar with the two-step approach to risk assessment. The operations department conducted "just-in-time" training on the specifics of Procedure AD7.DC6 for each of the operating crews. The inspectors concluded that this training sufficiently addressed the concern with the RHR flush and the lack of revision of the risk assessment.

c. Conclusions

Operators failed to revise the risk assessment of performing the RHR system flush during power operation when they elected to include removal of the boric acid storage tanks from service. Operators understood that the boric acid storage tanks were of low risk significance and, because of weak knowledge of the on-line maintenance risk assessment procedure, believed that a revision of the risk assessment was unnecessary. Subsequent evaluation of the risk associated with this activity confirmed the risk was low.

M1 Conduct of Maintenance

M1.1 Maintenance Observations

a. Inspection Scope (62707)

The inspectors observed all or portions of the following work activities:

- Work Order R0170936, Component Cooling Water Heat Exchanger 1-2, clean and inspect seawater side
- Install steam generator nozzle dams to support eddy current testing.

b. Observations and Findings

The inspectors concluded that each of these work activities was performed satisfactorily.

M1.2 Surveillance Observations

a. Inspection Scope (61726)

Selected surveillance tests required to be performed by the Technical Specifications were reviewed on a sampling basis to verify that: (1) the surveillances were correctly included on the facility schedule; (2) technically adequate procedures existed for the performance of the surveillances; (3) the surveillances had been performed at a frequency specified in the Technical Specifications; and (4) test results satisfied acceptance criteria or were properly dispositioned.

The inspectors observed all or portions of the following surveillances:

- STP M-81A Diesel Engine Generator Inspection (Every Refueling Outage), Revision 13
- STP M-9L Diesel Generator Shutdown Lockout Relay Test, Revision 21
- STP M-86G NUREG 0737: Charging System (Suction) Leak Reduction and Leak Check of Charging Pumps Suction, Revision 16

b. Observations and Findings

The inspectors concluded that each of these surveillance activities was performed satisfactorily.

M1.3 Loss of Spent Fuel Pool Cooling

a. Inspection Scope (62707, 92902)

The inspectors evaluated the licensee response to AR A0478430 and Quality Evaluation Q0012110, which identified an inadvertent loss of spent fuel pool cooling.

b. Observations and Findings

On February 25, 1999, at 5:06 p.m., operators received the Unit 1 "Spent Fuel Pool Level/Temp" annunciator in the control room. Upon checking the plant computer, operators recognized that the alarm resulted from an elevated temperature of 125°F in the spent fuel pool. The shift foreman dispatched a nuclear operator who noted that the local temperature gauge for the spent fuel pool indicated 126°F. The nuclear operator found that Spent Fuel Pool Pump 1-2 was not operating as required and restarted the pump. Since the cause of the trip was unknown at this time, the shift foreman directed hourly checks of Spent Fuel Pool Pump 1-2 to ensure continued operation. Following restart of the pump, spent fuel pool temperature gradually returned to the normal temperature of 100°F.

The licensee determined from operator logs taken on February 25 that Spent Fuel Pool Pump 1-2 was running at approximately 11 a.m, with a spent fuel pool temperature of 100°F. Upon search of plant records, the licensee determined that Relay CIAX-H (associated with the Containment Phase A isolation signal) had been replaced that day. One of the purposes of the control circuit for Relay CIAX-H is to trip the spent fuel pool cooling pumps during an accident to prevent overloading of the DEGs. Since Relay CIAX-H had been removed at approximately 1 p.m., the licensee concluded that spent fuel pool cooling had been lost for 4 hours. Engineers determined that the heatup rate was approximately 6°F per hour and that the time to boil the spent fuel pool was approximately 16 hours.

Upon review of Work Order 60444, the inspectors noted that the clearance associated with the procedure contained no precautions or limitations to notify operators of the trip of the spent fuel pool cooling pump when removing Relay CIAX-H. Had this precaution been in place, operators could have immediately restarted Spent Fuel Pool Pump 1-2, preventing the inadvertent heatup of the spent fuel pool. Because this precaution was not in the clearance associated with Work Order 60444, this maintenance activity was not appropriately preplanned for the circumstances. The failure to properly preplan the replacement of Relay CIAX-H is the second example of a violation of Technical Specifications 6.8.1.a. However, this Severity Level IV violation is being treated as a noncited violation, consistent with Appendix C of the Enforcement Policy. This violation is in the corrective action program as AR A0478430 and Quality Evaluation Q0012110 (50-275/99003-01).

The inspectors noted that a contributing cause to the event was the inadequate monitoring of the spent fuel pool. As of February 18, the Unit 1 core was fully offloaded, which significantly increased the heat load of the spent fuel pool. No control room indications or controls of spent fuel pool pumps or spent fuel pool temperature/level existed at Diablo Canyon. However, operators continued to check spent fuel pool

parameters every 12 hours, even though the heat load in the spent fuel pool had increased. The inspectors concluded that, with monitoring every 12 hours, margin existed for operators to take action prior to boiling in the spent fuel pool, since the time to boil was 16 hours. In addition, with the spent fuel pool temperature alarm set at 125°F, operators had sufficient time to restore spent fuel pool cooling prior to fuel pool temperature exceeding the design basis limit of 140°F. However, the inspectors concluded that failing to frequently monitor spent fuel pool temperature following a full core off-load was an example of nonconservative operation.

Following the loss of spent fuel cooling event of February 25, the licensee revised Procedure B-8DS1, "Core Unloading," Revision 21, to require checks of the operating spent fuel pump and spent fuel pool temperature every 2 hours while the core was offloaded. The inspectors concluded that this procedure change was appropriate.

c. Conclusions

The second example of a noncited violation of Technical Specification 6.8.1.a. for not properly preplanning maintenance, which was associated with replacing a relay that provided Phase A containment isolation capability (AR A0478430), was identified. The relay was removed without adequate precautions or consideration for the effect on plant equipment. As a result, the operating spent fuel pool cooling pump tripped from service without operator knowledge.

Operating procedures were not conservative with respect to monitoring spent fuel pool temperature since increased temperature monitoring was not required with a full core offload in the spent fuel pool. Operators continued to monitor the Unit 1 spent fuel pool temperature every 12 hours. As a result, following an inadvertent trip of Spent Fuel Cooling Pump 1-2, the pump trip went undetected for 4 hours, until a spent fuel pool high temperature annunciator alarmed.

M1.4 Unit 1 Loss of 500 kV and DEG Start

a. Inspection Scope (61726, 92902)

The inspectors evaluated the licensee response to a Unit 1 turbine trip signal that occurred on March 3, 1999, while the unit was in Mode 6.

b. Observations and Findings

On March 3, while Unit 1 was in Mode 6, in parallel with the preparations being made to test the Bus G auto transfer to DEG 1-2, the main turbine oil and condensate systems were being returned to service. At approximately 3 p.m., a turbine trip signal caused the auto-transfer of the Unit 1 electrical buses from the 500 kV offsite auxiliary power source to the 230 kV offsite startup power source. Vital Bus G did not transfer because its startup feeder breaker was in the "Test" position in preparation for DEG 1-2 surveillance testing, as specified in Procedure M-13G, "4 kV Bus G Non-SI Auto-Transfer Test," Revision 16A. DEG 1-2 automatically started and the bus loads stripped, as designed for a loss of offsite power. As a consequence, RHR Pump 1-1 tripped (pump providing shutdown cooling), as well as Spent Fuel Pool Pump 1-2. The loads did not sequence

onto Bus G because no safety injection signal was present. Operators responded promptly to restart RHR Pump 1-1 within 39 seconds and Spent Fuel Pool Pump 1-2 within approximately 5 minutes. After stabilizing the plant, the operators paralleled DEG 1-2 to startup power, then unloaded, separated, and secured DEG 1-2.

Prior to restoring the 500 kV auxiliary power to Unit 1, Operations investigated the event to gain a basic understanding of its cause. At the beginning of the refueling outage on February 7, Unit 1 electrical buses were transferred to the 230 kV startup power, and the unit was separated from the grid. Subsequently, auxiliary power was restored for backfeeding in accordance with Procedure OP J-2:V, "Backfeeding the Unit from the 500 kV System," Revision 3B, and electrical buses were transferred back to the 500 kV auxiliary power. Part of Procedure OP J-2V applies administrative tagouts to disable turbine protection related trips that could open the 500 kV generator output breakers. At this time, operators properly disabled turbine thrust bearing wear trip along with other turbine trips.

On February 13, electrical buses were transferred to startup power, and the 500kV transformer banks were cleared for outage-related maintenance. On February 25, maintenance was completed, and operators were assigned to restore the 500 kV auxiliary power. During the restoration, operators used Procedure OP J-2:I, "Main and Aux Transformer Return to Service," Revision 9, to restore the 500 kV power. Procedure OP J-2I specifically directs placing the transformer protection switches in service but is vague about positioning the other turbine trip protection switches. In the absence of specific guidance, the operators erroneously placed the thrust bearing wear trip in service. The failure to properly implement procedures for restoring the 500 kV electrical power is a violation of Technical Specification 6.8.1a because of its impact on safety-related equipment. This Severity Level IV violation is being treated as a noncited violation, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the corrective action program as AR A0479274 and Nonconformance Report N0002089 (50-275/99003-03).

Also, the licensee investigated the cause of the high thrust bearing wear trip. Various turbine and generator related oil pumps were being restored and tested throughout the day. Because the main turbine thrust bearing trip nozzle assembly had not yet been aligned, the thrust bearing was in a position that caused the trip oil pressure to rise above its trip setpoint when the auto-stop oil system was pressurized by the pump starts. After understanding the basic steps that led to the Unit 1 trip, on-the-spot procedure changes were made to incorporate the specific instructions outlined in Procedure OP J-2:V to disable turbine protection related trips that could potentially open the 500 kV breakers. Operators used the revised procedures to restore 500 kV power. Approximately 3½ hours elapsed from the time of loss of 500 kV auxiliary power until its restoration.

The inspectors agreed with the assessment that procedure deficiencies led to the misalignment of the thrust bearing trip switch and contributed to the turbine trip. However, the inspectors concluded that the operators who performed the procedure should have clarified the unclear procedure guidance before positioning trip circuits. Operations personnel subsequently reviewed similar electrical restoration procedures, and several changes were made to clarify vague guidance on positioning trip circuits.

Also, the licensee identified a weakness in the sequence of steps for performing the auto-transfer test. Procedure M-13G requires that the Bus G startup feeder breaker be racked into the "Test" prior to simulating the loss of 500 kV auxiliary power. Subsequent steps in the procedure instruct the operators to start RHR Pump 1-2, which is powered by Bus H, since the Bus G RHR pump will be stripped off the bus and not automatically restarted. Operators concluded that Procedure M-13G could be improved by placing the step to start the other RHR pump prior to the step to rack the Bus G startup feeder breaker into the "Test" position.

c. Conclusions

A noncited violation of Technical Specification 6.8.1a. for failing to provide a procedure appropriate to the circumstances (AR A0479274) was identified. In this instance, the procedure used to restore the 500 kV offsite power source, in this instance, provided vague guidance for positioning the main turbine protective trip switches. In addition, lack of a questioning attitude on the part of operators restoring the 500 kV power contributed to the trip signal, partial loss of offsite power, and inadvertent DEG start. Operator response in restoring shutdown and spent fuel pool cooling following the loss of 500 kV power was good.

M1.5 Failure of DEG 1-1 to Pass Time-to-Rated Voltage Test

a. Inspection Scope (61726)

The inspectors evaluated the response to Quality Evaluation Q0012109 and associated AR A0478728, which described the failure of DEG 1-1 to reach rated voltage within the 13-second acceptance criteria limit during a performance test.

b. Observations and Findings

During a timed start of DEG 1-1 on February 27, 1999, the DEG took 20.4 seconds to reach 4160 volts. This exceeded the test acceptance criteria of 13 seconds and was considered to be a valid Maintenance Rule functional failure of DEG 1-1. During the timed start, engineers observed that voltage increased to approximately 2000 volts, hesitated for approximately 6 seconds, then rapidly rose to the required 4160 volts. During a normal DEG start, excitation voltage is initially supplied to the motor generator windings until a point of approximately 2700 volts. At approximately 2700 volts, the K3 relay opens to allow the voltage regulator to control the voltage increase to 4160 volts. Below 2700 volts, the voltage regulator is inefficient. Without the aid of the excitation voltage, the DEG would be unable to reach its rated 4160 volts within the required 13 seconds.

The engineers conducting the test remembered that a similar problem had occurred in August/September 1998 and that part of the corrective action involved replacing the K3 relay. Consequently, the engineers decided to replace the K3 relay before resumption of testing. The engineers who decided to replace the K3 relay did not realize at this time that DEG 1-1 was the same DEG that had the K3 relay replaced in September 1998.

Prior to retesting DEG 1-1, engineers reviewed a troubleshooting guide provided by Besler Electric, the manufacturer of the exciter and the voltage regulator. In order to gather more information to monitor symptoms, two Windowgraf recorders were installed to monitor generator output voltage, DC field voltage and current, relay actuation voltage, and transformer current. The inspectors considered the use of the additional test monitoring equipment to be a prudent measure but opined that the licensee had missed an additional opportunity to diagnose the problem by replacing the K3 relay prior to resumption of testing. The licensee bench tested the removed K3 relay and determined that the K3 relay behaved normally during its bench tests.

Following installation of the Windowgraf recorders, from February 28 through March 4, five tests were performed with no additional failures. DEG 1-2 was monitored to obtain the same test data as for DEG 1-1 as a benchmark. Test data for the five DEG 1-1 tests and the DEG 1-2 test were similar; consequently, the licensee considered DEG 1-1 to be operable. Since the additional test data was not sufficient to measure all of the voltage regulator control card parameters, the licensee replaced the voltage regulator control card. Seven successful tests were performed subsequent to the voltage regulator card replacement.

Because of the failures on DEG 1-1 in August 1998 and February 1999, DEG 1-1 was being tested weekly in accordance with Technical Specification requirements. As of the end of the inspection period, the licensee had only two more Technical Specifications tests to be conducted on the accelerated frequency of once per week versus monthly. However, the troubleshooting plan recommended that the accelerated testing be continued for an additional ten instrumented tests beyond that required by the Technical Specifications.

c. Conclusions

Following the failure of DEG 1-1 to reach rated voltage within its acceptance criteria, troubleshooting to determine the cause of the problem was generally thorough and identified a suspect voltage regulator. Troubleshooting appropriately considered vendor recommendations, and collected data and the number and frequency of tests exceeded requirements.

M8 Miscellaneous Maintenance Issues (92700)

M8.1 (Closed) Violation 50-275/97003-04: failure to take adequate corrective actions to correct deficiencies in the painting program.

This violation was issued as a result of an improperly painted governor valve linkage on Turbine-Driven Auxiliary Feedwater Pump 1-1. On February 28, 1997, the licensee declared Turbine-Driven Auxiliary Feedwater Pump 1-1 inoperable because the paint on the governor valve linkage could potentially impair its movement. Subsequently, the licensee issued Licensee Event Report 50-275/97-004-01 to describe this event.

The issues discussed in the licensee event report were discussed in NRC Inspection Report 50-275; 323/97-03 and in the violation response letter dated June 18, 1997. The inspectors verified the corrective actions described in the violation response letter and licensee event report to be reasonable and complete.

M8.2 (Closed) Licensee Event Report 50-275/97-004-01: Technical Specification 3.7.1.2 not met because of paint applied to auxiliary feedwater pump turbine governor linkage because of personal error.

Closure of this followup item is discussed in Section M8.1.

E1 Conduct of Engineering

E1.1 Fibrous Material in Containment

a. Inspection Scope (37551)

The inspectors evaluated the corrective actions related to AR A0477669, which discussed the potential for fibrous material in containment to impact the operability of the containment recirculation sumps.

b. Observations and Findings

On October 22, 1998, upon review of an operating experience report from another facility, the licensee identified the potential for fibrous material in fire stops of vertical cable trays to impact containment recirculation sump operability. The engineers were concerned that this fibrous material could be transported to the containment recirculation sumps, clog the sumps, and cavitate the operating RHR pumps during the recirculation phase of a design basis accident. The licensee initiated AR A0477669 to enter this item into the corrective action program.

As-built drawings did not have sufficient detail to identify the exact location or quantity of this fibrous material. Based on discussions with personnel that performed repairs on fire stops, the licensee surmised that vertical cable tray fire stops consisted of fibrous materials known as Kaowool or Marinite. Because of the lack of sufficient detail, engineers could not initially determine if the fibrous material was installed in jet-impingement zones or subject to the effects of high energy line breaks. Based on the unknown status of the fibrous material, engineers coded this AR As an "issue needing validation to determine the impact on operability" and did not perform a prompt operability assessment. The prompt operability assessment was scheduled for performance during Refueling Outage 1R9 in February 1999.

On February 20, 1999, during Refueling Outage 1R9, the licensee inspected the Unit 1 containment to determine the exact location and quantity of fibrous material. The licensee evaluated or removed the fibrous material the Unit 1 containment located in jet impingement zones. The inspectors reviewed the licensee action with respect to Unit 1 and concluded that the action was satisfactory.

On February 20, the licensee performed a prompt operability assessment for Unit 2. Although the licensee did not inspect Unit 2, the licensee noted that both units were reasonably similar. Ten specific postulated pipe break locations on Unit 1 had significant fibrous material that could potentially be released in a jet-impingement zone. Engineers evaluated the operability of the Unit 2 containment recirculation sumps based on the Unit 1 information, using accepted transport phenomena calculations. The engineers determined that, although the net positive suction head of the RHR pumps was decreased, adequate margin for operability existed. The inspectors reviewed the Unit 2 operability assessment and determined it was satisfactory.

Although the inspectors concurred with the technical merit of the containment recirculation sump operability assessments, the inspectors questioned the timeliness of these evaluations. The inspectors noted that the operability of the sumps directly impacted safety and was considered risk significant. Generic Letter 91-18, "Resolution of Degraded and Nonconforming Conditions and Operability," stated that the timeliness of operability issues should be commensurate with the safety significance. However, the licensee had two missed opportunities to inspect the containment structures for fibrous material. Both Units 1 and 2 sustained forced outages in December 1998, yet licensee management deferred resolution of this issue until Refueling Outage 1R9.

c. Conclusions

The prompt operability assessment associated with fibrous material in fire stops in containment in both units, while technically sound, was not timely, given the potential safety significance of inoperable containment recirculation sumps. The operability question of the containment recirculation sumps was identified in October 1998. However, the prompt operability assessment was not completed until February 1999. The inspectors identified a deficiency in the operability process, specifically, the "issue needing validation to determine the impact on operability" portion. The licensee had missed two opportunities to perform a prompt operability assessment in December 1998 when forced outages had occurred in each unit.

E1.2 Modifications to the 230kV Offsite Power System

a. Inspection Scope

The inspectors reviewed the modifications to the offsite power system to address equipment reliability considerations and the divestiture of the Morro Bay Power Plant (Morro Bay) by Pacific Gas and Electric.

b. Observations and Findings

The 230 kV offsite power system at Diablo Canyon and the capabilities and configuration of Morro Bay were described in detail in the Final Safety Analysis Report, Section 8.2, "Offsite Power System," Revision 11, dated November 1996. The Final Safety Analysis Report described various configurations of Morro Bay and the effect of such configurations on the reliability of offsite power at the site. Additionally, the Final Safety Analysis Report provided information and references to plant procedures that addressed contingency actions. These contingency actions would need to be

accomplished at Diablo Canyon in the event of equipment failures or outages at Morro Bay in order to ensure adequate voltage for safety-related equipment.

In late 1997, the licensee began proceeding with modifications that would eliminate the dependence of the Diablo Canyon units on Morro Bay. These modifications replaced the existing startup transformers with load tap changing transformers and added shunt capacitors to eliminate the need for Morro Bay. These modifications resulted, in part, from the uncertainty associated with the economic viability of Morro Bay in a deregulated electrical environment that began in January 1998. In mid-February 1998, the licensee completed all of the planned modifications associated with the 230 kV offsite power system and subsequently divested itself of Morro Bay.

All of the changes to the facility and the divestiture of Morro Bay were conducted without prior approval by the NRC. The screening evaluations conducted by the licensee for the modifications concluded that the modifications to the offsite power system and the divestiture of Morro Bay did not constitute an unreviewed safety question and, therefore, did not require prior NRC approval. However, based on the questions raised by agency inspectors, the licensee initiated a management meeting with the NRC on December 22, 1997, and described the changes that had been made. As a result of the issues raised at that meeting, the licensee submitted a license amendment request to the NRC (Pacific Gas and Electric Letter DCL 98-008, dated January 14, 1998) seeking approval for the changes that had been implemented. The license amendment request described the modifications to the offsite power system and the elimination of the dependence of the facility on Morro Bay. In the submittal, the licensee asserted that the new configuration represented a safety improvement at the facility on the basis of the assumed superior reliability characteristics of the new equipment.

The inspectors noted that 10 CFR 50.59 states, in part, that a proposed change, test, or experiment shall be deemed to involve an unreviewed safety question if the possibility of an accident or malfunction of a different type than any evaluated previously in the safety analysis may be created. Further, the inspectors determined that the addition of the load tap changing transformers along with the shunt capacitors in lieu of the dependence on Morro Bay constituted a change to the facility as described in the Final Safety Analysis Report and that this change introduced the possibility of a malfunction of a different type than had been previously analyzed (e.g., the load tap changers may fail to adjust as required for changes in voltage or passive failure of the shunt capacitors). Thus, the inspectors determined that the 10 CFR 50.59 evaluation was inadequate and that these changes had resulted in an unreviewed safety question.

After consultation with the Director, Office of Enforcement, the NRC is exercising enforcement discretion in accordance with VII.B.6 of the Enforcement Policy and refraining from issuing a Notice of Violation. Discretion is appropriate because of: (1) confusion surrounding the determination of whether the change constituted an unreviewed safety question, (2) the similarity to other issues previously cited for which corrective actions have been taken and are sufficiently broad to address this violation (EA 98-364), and (3) the apparent improvement in grid reliability that resulted from the change (50-275; 323/99003-04).

c. Conclusions

On January, 14, 1998, a violation of 10 CFR 50.59 resulted because the licensee implemented a design change and failed to submit a license amendment for a change to the facility that involved an unreviewed safety question. The NRC, however, is exercising enforcement discretion in accordance with Section VII.B.6 of the enforcement policy and is refraining from issuing a Notice of Violation. The licensee changed the configuration of the 230 kV offsite power source from dependence on Morro Bay for operability to dependence on load tap changing transformers and capacitor banks. Corrective actions for previous 10 CFR 50.59 violations sufficiently addressed this issue. The design change improved the reliability of the 230 kV system.

E8 Miscellaneous Engineering Issues (92700, 92903)

E8.1 (Closed) Licensee Event Report 50-275/95-013-02 and -01: component cooling water system may have operated outside of its design basis

Because of the limited capacity of the auxiliary saltwater system combined with increases in the calculated heat load to the component cooling water system, the component cooling water system may have operated outside of its design basis. This issue was discussed in NRC Inspection Report 50-275; 323/98-05. No new issues were revealed by the licensee event report.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Reactor Coolant System Chloride Intrusion

a. Inspection Scope (71750, 92904)

The inspectors evaluated the licensee response to AR A0476360, which described an intrusion of chlorides into the reactor coolant system.

b. Observations and Findings

On February 8, 1999, chemistry personnel identified that, on Unit 1, reactor coolant system chlorides exceeded the Equipment Control Guideline limit of 150 ppb. The chloride concentration was 770 ppb and increased until a peak of 1060 ppb was reached. Chemists sampled the in-service chemical and volume control system deborating demineralizer and identified that the effluent chloride concentration was 1730 ppb. After operators isolated the in-service deborating demineralizer, the chloride concentration started decreasing and had returned within the specification of 150 ppb on February 10. Because reactor coolant system chlorides exceeded the limit by a significant margin, chemists initiated AR A0476360 to enter this item into the corrective action system.

Licensee investigation revealed that a chloride based resin was loaded into the deborating demineralizer for crud burst cleanup. However, the barrel in the Diablo Canyon warehouse was labeled with a licensee material tag stating that the resin was hydroxide based. The licensee contacted the resin vendor who confirmed that the barrel contained a chloride based resin.

Normally, when purchasing resin for use in the reactor coolant system, a receipt inspection program, which included testing of the resin, was implemented to ensure that the resin contained no detrimental properties. The licensee procured the resin as hydroxide based for use in the radwaste processing system. Because the resin was procured for a nonsafety-related function, no receipt inspection was performed. The barrel was labeled as an hydroxide based resin. Chemists noted that this resin was effective in processing radwaste streams and, therefore, recommended its use in the reactor coolant system. No testing or other confirmatory actions were taken when the chloride based resin was approved for use in the reactor coolant system.

The licensee initiated Nonconformance Report N0002084 because of the potential consequences of the chloride intrusion and the concerns with the resin procurement process. The inspectors agreed that the process for dedicating radwaste resin for use in the reactor coolant system was weak in that no testing or other confirmatory actions were employed. The licensee also identified several other barriers that should have prevented this deficiency. Procedure OP B-1A:XIII, "CVCS Demineralizers," Revision 13, step 1.1, specified, in part, that the demineralizer is to be rinsed and sampled prior to use. The effluent was to be routed to the liquid holdup tank while sampling. In addition, a CAUTION prior to Section 2 required verification that samples are taken to determine the effects of the demineralizer on reactor coolant system chemistry. The failure of licensee personnel to implement the steps of Procedure OP B-1A:XIII is the second example of a violation of Technical Specification 6.8.1.a. This licensee-identified Severity Level IV violation is being treated as a noncited violation, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the corrective action program as Nonconformance Report N0002084 (50-275/99003-02).

Forced oxygenation of the reactor coolant system using hydrogen peroxide was in progress when the chloride intrusion occurred. The licensee was initially concerned that the combination of high oxygen and chlorides in the reactor coolant system could result in the potential for chloride stress corrosion of reactor coolant system components. The licensee contacted the Nuclear Steam Supply System vendor who determined, based on the actual conditions, chloride stress corrosion was unlikely. The inspectors reviewed the vendor analysis and concluded that it was satisfactory. The inspectors also concluded that the root cause analysis and corrective action process addressed the issues appropriately.

c. Conclusions

The second example of a noncited violation of Technical Specification 6.8.1.a for failure to follow procedure resulted when chemists failed to sample the chemical and volume control system demineralizer prior to placing it in service (NCR N0002084). This error resulted in a significant chloride intrusion into the reactor coolant system and caused the

Equipment Control Guideline limit to be exceeded. In addition, the controls for the purchase, control, and dedication of resins for nonsafety-related applications were deficient. The licensee performed a detailed root cause analysis and corrective actions addressed the issues appropriately.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750)

During routine tours, the inspectors noted that the security officers were alert at their posts, security boundaries were being maintained properly, and screening processes at the Primary Access Point were performed well. During backshift inspections, the inspectors noted that the protected area was properly illuminated, especially in areas where temporary equipment was brought in.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on March 11, 1999. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. R. Becker, Manager, Operations Services
W. G. Crockett, Manager, Nuclear Quality Services
R. D. Gray, Director, Radiation Protection
T. L. Grebel, Director, Regulatory Services
D. B. Miklush, Manager, Engineering Services
D. H. Oatley, Vice President and Plant Manager
R. A. Waltos, Manager, Maintenance Services
L. F. Womack, Vice President, Nuclear Technical Services

INSPECTION PROCEDURES (IP) USED

IP 37551	Onsite Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Observation
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 92700	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901	Followup - Operations
IP 92902	Followup - Maintenance
IP 92903	Followup - Engineering
IP 92904	Followup - Plant Support
IP 93702	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED AND CLOSED

Opened

None.

Closed

50-275/97003-04	VIO	failure to take adequate corrective actions to correct deficiencies in the painting program (Section M8.1)
50-275/97-004-01	LER	Technical Specification 3.7.1.2 not met because of paint applied to auxiliary feedwater pump turbine governor linkage (Section M8.2)
50-275/95-013-02 and -01	LER	component cooling water system may have operated outside of its design basis (Section E8.1) .

Opened and Closed

50-275/99003-01	NCV	Improper maintenance clearance preplanning on nitrogen system during midloop and for relay replacement (Sections O1.2 and M1.3)
50-275/99003-02	NCV	Failure to enable RVRLIS alarm during midloop and failure to sample demineralizer as required (Sections O1.2 and R1.1)
50-275/99003-03	NCV	Inadequate maintenance procedure resulted in partial loss of offsite power (Section M1.4)
50-275; 323/ 99003-04	NCV	Failure to submit license amendment for changes to 230 kV offsite power system (Section E1.2)

LIST OF ACRONYMS USED

AR	action request
DEG	diesel engine generator
IP	inspection procedure
NCV	noncited violation
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
RHR	residual heat removal
RVRLIS	reactor vessel refueling level indication system
VIO	violation