ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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License Nos.:	NPF-10 NPF-15
Report No.:	50-361/99-16 50-362/99-16
Licensee:	Southern California Edison Co.
Facility:	San Onofre Nuclear Generating Station, Units 2 and 3
Location:	5000 S. Pacific Coast Hwy. San Clemente, California
Dates:	October 31 through December 11, 1999
Inspectors:	J. J. Russell, Acting Senior Resident Inspector J. G. Kramer, Resident Inspector J. A. Sloan, Senior Resident Inspector
Approved By:	Linda Joy Smith Chief, Branch E Division of Reactor Projects

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

San Onofre Nuclear Generating Station, Units 2 and 3
NRC Inspection Report No. 50-361/99-16; 50-362/99-16

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

Operations

- Operators thoroughly and methodically prepared for and conducted evolutions. Management and supervisors provided close oversight of operational activities. Procedure use and operator communications were generally consistent with written licensee management expectations (Section O1.1).

- Locking devices on two saltwater cooling heat exchanger outlet valves did not prevent removal of the operating chains that were used to restrain the valves and, therefore, were not adequate to prevent valve manipulation or provide evidence of unauthorized valve manipulation. A violation of Technical Specification 5.5.1.1.a resulted from the failure to properly lock a saltwater cooling heat exchanger outlet valve on each unit. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was in the licensee's corrective action program as Action Request 991200172 (Section O2.1).

- Maintenance and Operations personnel responsible for assessing risk and scheduling maintenance did not sufficiently understand the mechanics and status of the online risk monitor. This resulted in underestimating the risk associated with performing a turbine-driven auxiliary feedwater pump outage concurrent with high impact switchyard work. The inspectors subsequently determined that risk remained in the moderate range, which was in the same range as the original licensee assessment (Section O8.1).

- The Licensee-Controlled Specifications for the steam generator wide-range level instrumentation were poorly written (Section O8.2).

Maintenance

- Licensee personnel performed maintenance and surveillance activities in a thorough manner, with work packages present and in active use. Technicians were knowledgeable and professional. Supervisors and system engineers frequently monitored job progress, and Quality Control personnel were present whenever required by procedure. When applicable, appropriate radiation controls were in place (Sections M1.1 and M1.2).

- A prejob briefing conducted by a licensed operator in preparation for a semiannual emergency diesel generator fast start contained erroneous information. The crew was told to expect turbocharger exhaust leaks that had already been evaluated as acceptable, when in fact, these leaks had already been repaired. Further, direction was given to complete inservice testing of air-start system valves, which was neither required nor workable during an emergency diesel generator fast start (Section M1.3).

- Operations and Maintenance planning personnel were conservative by instituting work control measures in excess of programmatic and Technical Specification requirements during an 8-day scheduled emergency diesel generator outage. With the emergency diesel generator unavailable, Unit 2 risk remained in the normal range. The controls included restricting access to high risk components, restricting emergency diesel generator allowed outage time to less than Technical Specification-allowed outage time, and restricting switchyard work (Section M1.4).

- A violation of 10 CFR Part 50, Appendix B, Criterion III, resulted from the failure of the licensee to ensure that cable train separation criteria were maintained during a radiation monitor design change. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was in the licensee's corrective action program as Action Request 990900002. Although train separation was not maintained, this condition itself would not have prevented systems from performing their required emergency safety features function (Section M8.1).

Engineering

- Nuclear Regulatory Affairs personnel demonstrated inattention to detail by submitting a license amendment to increase the allowed outage time of an emergency diesel generator from 72 hours to 14 days, without noting that this allowed outage time conflicted with the Technical Specification 3.4.9 72-hour allowed outage time for pressurizer heaters. The heaters were not operable without an operable, associated emergency diesel generator. This resulted in the need for an exigent Technical Specification change, as opposed to a normal change, when the error was discovered by Operations personnel, and emergency diesel generator maintenance longer than 72 hours was scheduled (Section E8.1).

Plant Support

- A violation of Section 5.2.2 of the Physical Security Plan occurred when the inspectors identified that an escort failed to maintain visual observation of a visitor in a Unit 2 vital area. The presence of other badged personnel near the visitor, and the short duration of the occurrence, mitigated the significance of the violation; however, the violation was more than minor since it occurred in a vital area. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was in the licensee's corrective action program as Action Requests 991100185 and 991100195 (Section S1.1).

Report Details

Summary of Plant Status

Units 2 and 3 operated at essentially 100 percent reactor power during this inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors observed routine and nonroutine operational activities throughout this inspection period. Some of the activities observed included:

- Operator Rounds (Units 2 and 3)
- Shift turnover (Units 2 and 3)
- Stop Train B component cooling water/saltwater cooling pumps (Unit 2)
- Manual control of steam generator level (Unit 3)
- Train A emergency chiller start (Units 2 and 3)

Operators thoroughly and methodically prepared for and conducted evolutions. Management and supervisors provided close oversight of operational activities. Procedure use and operator communications were generally consistent with written licensee management expectations.

O2 Operational Status of Facilities and Equipment

O2.1 Locked Valves - Units 2 and 3

a. Inspection Scope (71707)

The inspectors performed routine plant walkdowns and identified two improperly locked valves. The inspectors discussed the observation with the control room staff and Operations management. The inspectors reviewed Procedure SO23-0-17, "Locking of Important to Safety Critical Valves and Breakers," Revision 13, ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," and NRC Inspection Manual, Part 9900: Technical Guidance STS_SURV.TG, "Standard Technical Specifications Surveillance Sections - Locked or Otherwise Secured Components," dated October 1, 1977.

b. Observations and Findings

On a 31-day frequency, Surveillance Requirement (SR) 3.7.8.1 requires the licensee to verify each saltwater cooling system manual valve that is in the flow path servicing safety-related systems or components is in the correct position, unless the valve is locked, sealed, or otherwise secured in position. However, on October 28, 1999, the inspectors identified that the licensee was not performing this verification for saltwater cooling Heat Exchanger ME002 Outlet Valves 2HCV6457 and 3HCV6457, and that these chain-operated valves were not adequately locked. With minimal effort, a person could remove the operating chains from Valves 2HCV6457 and 3HCV6457, reposition the valves, and replace the operating chains without the valves showing evidence of tampering.

The aforementioned Part 9900 technical guidance to inspectors documents the NRC's intent regarding "locked, sealed, or otherwise secured components" as used in the surveillance sections of Standard Technical Specifications, other Technical Specifications, and the Safety Analysis Reports. Section 1, which addresses manually-operated valves, states the following:

"a. The valve should be physically restrained from moving. The methodology by which the restraint is removed should be under administrative control. A key or combination lock is the preferred methodology, but the use of a "sealing" technique which will provide evidence of unauthorized manipulation is acceptable (e.g., cable secured by means of a lead seal).

b. A tag or similar device on a valve handwheel does not meet the requirements for a locked valve in a fluid system important to safety. Likewise, simply removing the valve handwheel without securing the stem in position is inadequate."

Two links in the operating chain for Valves 2HCV6457 and 3HCV6457 were locked to themselves, and each lock was also loosely attached by a wire cable to a fixed structure. The inspectors noted that Valves 2HCV6457 and 3HCV6457 were physically restrained from moving when the locks and chains were in place. However, sufficient play existed in the operating chains to allow removal of these restraints without unlocking the locks. The inspectors determined that the locks did not prevent manipulation of the valves. Specifically, the lock did not control removal of the operating chain and a "sealing" technique which provided evidence of unauthorized manipulation was not used. Therefore, the inspectors concluded that the licensee was required to verify the position of these valves every 31 days as specified in SR 3.7.8.1.

Operations management believed that the valves were adequately locked and indicated that the intent of their locked valve program was not to provide evidence of unauthorized manipulation but to help prevent inadvertent manipulation of the valves. The Nuclear Regulatory Affairs manager indicated that there was not a requirement to have the locked valve program provide evidence of unauthorized manipulation.

The inspectors agreed that manually or power-operated components, for which requirements are not specified in the Technical Specifications or the Updated Final Safety Analysis Report, may be controlled by whatever procedures the licensee has developed for that purpose. However, for items specifically designated in Safety Analysis Reports or Technical Specifications as being locked, the NRC has used NRC Inspection Manual, Part 9900: Technical Guidance STS_SURV.TG, "Standard Technical Specifications Surveillance Sections - Locked or Otherwise Secured Components," to interpret the meaning of NRC locked valve license requirements since October 1, 1977. Use of this guidance predates the issuance of operating licenses for San Onofre Nuclear Generating Station, Units 2 and 3.

The inspectors also noted that the licensee committed to ANSI N18.7-1976 in the Updated Final Safety Analysis Report. ANSI N18.7-1976, Section 5.2.6, "Equipment Control," specifies that "Procedures shall be provided for control of equipment . . . to avoid unauthorized operation of equipment. These procedures shall require control measures such as locking or tagging to secure and identify equipment in a controlled status."

The inspectors discussed this issue with the Chief of the Technical Specification Branch of the NRC Office of Nuclear Reactor Regulation. The Branch Chief agreed that the locking method used by the licensee for the chain-operated saltwater cooling valves was not adequate or consistent with the intent of Part 9900 and did not ensure that the valves were locked, sealed, or otherwise secured in their correct position in the context of SR 3.7.8.1.

Technical Specification 5.5.1.1.a requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, recommends procedures for equipment control.

Procedure SO23-0-17, "Locking of Important to Safety Critical Valves and Breakers," Revision 13, step 6.1.3, requires, in part, that manually-operated valves listed in Attachments 1 - 10 shall be locked in the specified position and should be locked using positive locking devices. Further, Procedure SO23-0-17 requires that locking devices should be positioned in a manner that will prevent valve operation and that the valve locking device should restrict valve movement as much as practical. Attachment 5 lists Valve HCV6457 as locked open.

Contrary to the above, on October 28, 1999, Procedure SO23-0-17 was not implemented, in that, in both Units 2 and 3, Valve HCV6457 was open but not locked. A locking device was installed; however, the locking device was insufficient to prevent valve manipulation or provide evidence of unauthorized valve manipulation, because the locking device did not prevent removal of the operating chains that restrained the valves. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (NCV 361/9916-01; 362/9916-01). This violation was in the licensee's corrective action program as Action Request 991200172.

The licensee performed several actions in response to this issue. On October 28, 1999, Operations management directed that Valve HCV6457 be verified open on both units. Operators found the valves open with a locking device installed. On November 5, 1999, the licensee initiated a temporary change notice to Procedure SO23-3-3.18 to include Valves 2HCV6457 and 3HCV6457 in the component cooling water/saltwater cooling system monthly test. This test, in part, verifies that each manual valve servicing safety-related equipment that is not locked is in its correct position. In addition, the licensee initiated Action Request 991200172 to further evaluate the issue.

c. Conclusions

Locking devices on two saltwater cooling heat exchanger outlet valves did not prevent removal of the operating chains that were used to restrain the valves and, therefore, were not adequate to prevent valve manipulation or provide evidence of unauthorized valve manipulation. A violation of Technical Specification 5.5.1.1.a resulted from the failure to properly lock a saltwater cooling heat exchanger outlet valve on each unit. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was in the licensee's corrective action program as Action Request 991200172.

08 Miscellaneous Operations Issues

O8.1 Risk Assessment

a. Inspection Scope (71707, 62707)

The inspectors reviewed licensee assessment of risk related to planned maintenance.

b. Observations and Findings

On November 16, 1999, the inspectors noted that Unit 3 turbine-driven auxiliary feedwater (TDAFW) Pump 3P140 and associated discharge valves had been removed from service for scheduled maintenance. The maintenance included adjustments to, and motor-operated valve analysis of, the discharge valves and minor maintenance on the pump. During the 2.5-day scheduled maintenance period, high impact switchyard work also occurred. The high impact work consisted of hot washing the 220 KV switchyard ring bus, emergency battery replacements for various switchyard breakers, and work that disabled one offsite power source (Encino line). Also, the inspectors noted that a starting air compressor was being repainted for the Train A emergency diesel generator (EDG), which could have affected diesel generator availability. The EDG remained available and the loss of the starting air compressor was below the modeled threshold for risk.

The inspectors questioned the scheduling of high impact switchyard work at the same time that the TDAFW pump was unavailable. The switchyard work increased the probability of a plant-initiated loss of offsite power. In addition, the TDAFW pump was a success path to providing core heat removal in the event that onsite power was lost.

The licensee had determined that the instantaneous core damage frequency for the above configuration was 2.02 E-04/yr, which placed Unit 3 in a moderate risk configuration. Responsible Operations and Maintenance personnel stated that, because of a recently installed and functional ability to cross-tie vital buses between Units 2 and 3, the switchyard no longer had an affect, from a risk perspective, on loss of offsite power. Consequently, scheduling no longer needed to consider prohibiting switchyard activities unless an EDG was out of service. Also, the online risk monitor no longer provided an option to input high impact switchyard maintenance into the risk assessment. The 2.02 E-04/yr risk number had been generated based solely on the TDAFW pump being unavailable.

The inspectors subsequently determined this estimate of risk was incorrect because the high impact switchyard activities did affect total risk. The online risk monitor option for high impact switchyard maintenance had been removed by the licensee Probabilistic Risk Assessment (PRA) group. The PRA group removed the ability to assess high impact switchyard activities after they noticed abnormal cut sets being produced by the online risk monitor when the option was used. While a multiplier (5.8) for the frequency of loss-of-offsite power events had been included to estimate the risk increase caused by the switchyard activities, the division between plant initiated and nonplant initiated offsite power events was not being modeled correctly and the error overestimated risk. The PRA group had intended to debug the monitor and reestablish the switchyard risk option.

The inspectors determined that Operations and Maintenance personnel did not understand that removal of the option to model high impact switchyard activities resulted in a low estimate of risk whenever high impact switchyard maintenance was occurring. The personnel also did not understand that the removal of the option was only temporary. In response, Operations management planned to incorporate PRA training using required readings and the requalification process.

Neglecting the risk from the switchyard activities, the licensee calculated the instantaneous core damage frequency as 2.02E-04/yr, which equated to an allowed outage time of 58 hours for the TDAFW pump. For TDAFW pump maintenance coincident with high risk switchyard activities, the licensee estimated the instantaneous core damage frequency as 4E-04/yr, which equated to 23 hours allowed outage time. Since the switchyard activities were expected to take 16 hours, the licensee continued with their schedule. On November 18, 1999, the PRA group debugged the online risk monitor and re-estimated plant risk as 2.30E-04/yr, which equated to 50 hours of allowed outage time for TDAFW pump maintenance.

c. Conclusions

Maintenance and Operations personnel responsible for assessing risk and scheduling maintenance did not sufficiently understand the mechanics and status of the online risk monitor. This resulted in underestimating the risk associated with performing a TDAFW pump outage concurrent with high impact switchyard work. The inspectors subsequently determined that risk remained in the moderate range, which was in the same range as the original licensee assessment.

O8.2 Inoperable Recorders - Units 2 and 3

a. Inspection Scope (71707)

On November 30, 1999, the inspectors reviewed the circumstances surrounding the actions of Units 2 and 3 operators when they declared steam generator wide-range level recorders inoperable. Both units had entered Technical Specification 3.3.11 for one channel of postaccident monitoring instrumentation inoperable. The inspectors reviewed Licensee-Controlled Specification (LCS) 3.7.113, "10 CFR Appendix R Safety Shutdown Components," and portions of Procedure SO23-3-3.35, "Post-Accident Monitoring Instrumentation Monthly Checks," Temporary Change Notice 13-1.

b. Observations and Findings

Unit 2 operators declared Level Recorder 1125-1 inoperable and Unit 3 operators declared Level Recorder 1125-1 inoperable because the recorders were inking excessively, tearing the chart paper, and indicating excessive deviations in level. Technical Specification SR 3.3.11.2 directed that the operators perform a channel check of the postaccident monitoring instruments once every 31 days.
Procedure SO23-3-3.35 accomplished this channel check by comparing the recorders to indicators and separately comparing indicators to indicators. Although the Technical Specification did not mention recorders as being required for the postaccident monitoring instrument indication, the licensee incorporated the recorders into the channel check because of guidance in Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident."

The inspectors reviewed LCS 3.7.113 and noted that LCS SR 3.7.113.2 directed a channel check of Appendix R instrumentation applicable to the associated steam generator level instruments be performed "per SR 3.3.11.2." The operators had declared the level recorders inoperable, which prevented performing the channel check as described in Procedure SO23-3-3.35. Consequently, the inspectors questioned how the operators satisfactorily completed the channel check required by LCS SR 3.7.113.2. In response, the Operations manager stated that the "per" in LCS SR 33.7.113.2 was meant to simply facilitate performance of the SR and that Appendix R requirements did not include recorders, only indicators. Also, the Operations manager stated that the acceptance criteria for Procedure SO23-3-3.35 were intended to be applied separately and differently for Technical Specification 3.3.11 and LCS 3.7.113, despite the "per" in LCS SR 3.7.113.2. Procedure SO23-3-3.35 did not differentiate acceptance criteria between Technical Specification SR 3.3.11.2 and LCS SR 3.7.113.2

The inspectors found that the intent of LCS SR 3.7.113.2 was not clearly described in the LCS nor in the implementing procedure. The licensee generated Action Request 991101537 to clearly establish separate acceptance criteria for the channel checks described above and to delete the "per" in LCS SR 3.7.113.2.

c. Conclusions

The LCSs for steam generator wide range level instrumentation SRs were poorly written.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

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

- EDG 2G002 engine analysis (Unit 2)
- Replace TDAFW Pump 3P140 steam supply Root Valve 3MR1241 (Unit 3)
- Perform motor-operated valve analysis and testing and manual clutch adjustment on auxiliary feedwater to Steam Generator 3E089 Control Valve 3HV4706 (Unit 3)
- Verify timing and perform cylinder lining inspection on EDG 2G002 (Unit 2)

b. Observations and Findings

The inspectors found the work performed under these activities to be thorough. All work observed was performed with the work package present and in active use. Technicians were knowledgeable and professional. The inspectors frequently observed supervisors and system engineers monitoring job progress, and Quality Control personnel were present whenever required by procedure. When applicable, appropriate radiation controls were in place.

In addition, see the specific discussions of maintenance observed under Section M1.4, below.

M1.2 General Comments on Surveillance Activities

a. Inspection Scope (61726)

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

- Verify EDG 2G002 fuel oil transport system operability (Unit 2)
- Plant protection system Channel C functional test (Unit 3)

b. Observations and Findings

The inspectors found all surveillances performed under these activities to be thorough. All surveillances observed were performed with the work package present and in active use. Technicians were knowledgeable and professional. The inspectors frequently observed supervisors and system engineers monitoring job progress, and Quality Control personnel were present whenever required by procedure. When applicable, appropriate radiation controls were in place.

In addition, see the specific discussions of surveillances observed under Section M1.3, below.

M1.3 Diesel Generator Monthly Test - Unit 2

a. Inspection Scope (61726)

On December 6, 1999, the inspectors observed performance of Procedure SO23-3-3.23, Attachment 1, "Diesel Generator Operation," Temporary Change Notice 15-1. Operators performed a semiannual fast start of EDG 2G002 in order to satisfy Technical Specification SR 3.8.1.7 and to demonstrate postmaintenance operability. The inspectors observed the pre-evolution briefing (tailboard) conducted by the common control operator and local EDG operation.

b. Observations and Findings

During the tailboard, the common control operator informed the personnel conducting the surveillance that there might be exhaust leaks from the Engine 2 turbocharger, which did not affect operability. The inspectors noted that the Engine 2 turbocharger had just been replaced during the maintenance outage. The inspectors questioned why the new turbocharger would have exhaust leaks. The common control operator had based his erroneous information on an electronic mail message sent by the cognizant engineer. Since exhaust leaks were not anticipated from the new turbocharger, the information was corrected.

Procedure SO23-3-3.23, steps 2.3.1 and 2.3.9, contained checks of air-start motor valve function. During the tailboard, the common operator directed that these checks be performed; however, these steps were not intended to be performed during semiannual EDG fast starts when both trains of starting air were in service. The checks of air-start motor valve function, and the acceptance criteria, identified only one train of starting air in service, which was the configuration during monthly EDG starts. Also, the inservice testing program did not require these checks to be performed during the semiannual starts. The direction by the common operator confused the equipment operator performing the checks locally, who initially determined that one-half of each train of starting air had failed a valve open check. In addition, the control room operators concluded that both trains of starting air passed a valve closed check. Neither one of these determinations were necessarily correct, because the acceptance criteria were intended for a single train of starting air to be aligned. In response, Action Request 991200334 was issued to enhance Procedure SO23-3-3.23, in order to make these steps not applicable during semiannual fast starts.

c. Conclusions

A prejob briefing conducted by a licensed operator in preparation for a semiannual EDG fast start contained erroneous information. The crew was told to expect turbocharger exhaust leaks that had already been evaluated as acceptable, when, in fact, these leaks had already been repaired. Further, direction was given to complete inservice testing of air-start system valves, which was neither required nor workable during an EDG fast start.

M1.4 EDG 2G002 Outage - Unit 2

a. Inspection Scope (62707, 71707)

The inspectors observed work control in effect during an 8-day scheduled maintenance outage for EDG 2G002.

b. Observations and Findings

From November 29 through December 6, 1999, personnel conducted a scheduled maintenance outage for EDG 2G002. The unavailability of this EDG caused an instantaneous core damage risk of 8.6E-5/year, which was in the normal range. During this maintenance activity, the licensee instituted equipment control practices in excess of normal. These controls included: restricting high impact switchyard work, not issuing verbal or written work authorization for Unit 2 Train B equipment, minimizing authorized EDG outage time to 10 days even though the Technical Specifications-allowed outage time was 14 days, and barricading and restricting entrance to the Train B EDG room, the auxiliary feedwater pump room, a control building relay room, and the Unit 3 Train A EDG. The inspectors walked down these spaces and components and found no discrepancies or operability concerns.

c. Conclusions

Operations and Maintenance planning personnel were conservative by instituting work control measures in excess of programmatic and Technical Specifications requirements during a scheduled 8-day EDG outage. With the EDG unavailable, Unit 2 risk remained in the normal range. The controls included restricting access to high risk components, restricting EDG allowed outage time to less than Technical Specifications-allowed outage time, and restricting switchyard work.

M8 Miscellaneous Maintenance Issues (92700)

M8.1 (Closed) Licensee Event Report 361; 362/1999-005-00: loss of physical separation in the control room.

The inspectors reviewed the circumstances regarding the loss of physical separation in the control room during a design change that replaced the radiation monitors and associated control room instrument cabinets. On August 31, 1999, the shift manager and the shift technical advisor discovered that the Trains A, B, and X instrumentation, control, and power cables were lying adjacent to each other. The licensee declared the affected equipment inoperable and entered the applicable Technical Specification action statements.

The licensee indicated that Updated Final Safety Analysis Report, Section 7.1.2, states, in part, that the design basis for instrumentation and controls for the reactor protection system and emergency safety features system conforms to IEEE Standard 279-1971. IEEE 279 states, in part, that channels that provide signals for the same plant protective function shall be independent and physically separated to accomplish decoupling of the effects of unsafe environmental factors, electrical transients, and physical accident consequences documented in the design basis. In addition, Updated Final Safety Analysis Report, Sections 7.1.2.29 and 8.3.3.3 describes a 6-inch minimum physical separation or specifies providing an electrical arc and fireproofing tape as meeting the requirements of Regulatory Guide 1.75.

The licensee attributed the root cause to failure to modify the work plan after revising the work scope for completing the modifications to the panels. Late in the planning process, personnel changed the design from having associated equipment removed from service to having some equipment in service. However, the personnel involved did not recognize the need to re-review the design change package for train separation criteria. Additionally, a special test procedure, written to control the movement of the cables, did not contain a caution to maintain train separation, and the construction work orders work plan did not address any cable separation issues.

Appendix B, Criterion III, of 10 CFR Part 50, "Design Control," states, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into procedures and instructions. The failure of the licensee to ensure that cable train separation criteria were maintained during the radiation monitor design change was a violation of Criterion III. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (NCV 361; 362/99016-02). This violation was in the licensee's corrective action program as Action Request 990900002.

The inspectors reviewed the safety consequence of the event. The affected circuits consisted of relay control power, control power, and current limited radiation monitor signals. The control and power circuits were protected by fuses and breakers that protect the cables and equipment from fire damage in the event of a short circuit. The licensee concluded that the short sections of the cables that were not properly separated resulted in a small reduction in the single failure protection of these circuits. In addition, the licensee concluded that, although the trains were not separated as required, this condition itself would not have prevented the systems from performing their required emergency safety features functions.

III. Engineering

E8 Miscellaneous Engineering Issues

E8.1 License Amendment Submittal - Units 2 and 3

a. Inspection Scope (37551)

The inspectors reviewed the circumstances surrounding a licensee submittal to the NRC Office of Nuclear Reactor Regulation for an exigent license amendment. The submittal requested deletion of a phrase in Technical Specifications stating that two groups of pressurizer heaters "be capable of being powered from an emergency power supply." The inspectors reviewed the submittal, "Amendment Application Numbers 192 and 177 to Facility Operating Licenses NPF-10 and NPF-15, for Units 2 and 3," dated November 10, 1999, and an earlier license amendment submittal, issued by the NRC, that requested changing the allowed outage time of a single EDG from 72 hours to 14 days, dated July 22, 1998. The inspectors also interviewed Nuclear Regulatory Affairs personnel.

b. Observations and Findings

Technical Specification 3.4.9, "Pressurizer," required that two groups of pressurizer heaters be operable and capable of being powered from an emergency power supply. The allowed outage time for these heaters was 72 hours. The licensee planned to perform a scheduled 5-day Unit 2, Train A, EDG 2G002 maintenance outage commencing November 29, 1999. Early in November, Operations personnel noticed that Technical Specification 3.4.9 would require a unit shutdown if the EDG was inoperable for longer than 72 hours, because the heaters powered from Train A would no longer be capable of being powered from an emergency power supply. In response, Nuclear Regulatory Affairs submitted an exigent Technical Specification amendment request. The Office of Nuclear Reactor Regulation subsequently granted the change prior to the scheduled EDG outage starting date. The inspectors noted that the 14-day EDG allowed outage time had been changed from 72 hours as a result of an earlier licensee submittal.

The inspectors found that this earlier submittal was consequently incomplete, because Nuclear Regulatory Affairs personnel had failed to note the contradiction in the Technical Specifications; specifically, the 14-day EDG allowed outage time would be prevented by the 72-hour allowed outage time for the same train pressurizer heaters. Nuclear Regulatory Affairs personnel stated that they had interpreted being "capable of being powered from an emergency power supply" as meaning that the pressurizer heaters were powered from a safety-related bus. This resulted in the Technical Specification 3.4.9 submittal being processed on an exigent basis, instead of normally, in order to meet the scheduled EDG outage starting date.

c. Conclusions

Nuclear Regulatory Affairs personnel demonstrated inattention to detail by submitting a license amendment to increase the allowed outage time of an EDG from 72 hours to 14 days, without noting that this allowed outage time conflicted with the Technical Specification 3.4.9 72-hour allowed outage time for pressurizer heaters. The heaters were not operable without an operable, associated EDG. This resulted in the need for an exigent Technical Specification change, as opposed to a normal change, when the error was discovered by Operations personnel, and EDG maintenance longer than 72 hours had been scheduled.

IV. Plant Support

S1 Conduct of Security and Safeguards Activities

S1.1 Unescorted Visitor in Vital Area - Units 2 and 3

a. Inspection Scope (71750)

The inspectors observed security practices during a routine maintenance activity in the Unit 2 diesel building.

b. Observations and Findings

On November 3, 1999, during routine maintenance on EDG 2G002, the inspectors identified that an assigned escort was not in sight of any visitors. The escort had just come from the opposite side of the diesel engine. When confronted by the inspectors, the escort immediately returned to the side of the diesel engine with the visitor.

Although the assigned escort was solely responsible for performing the escort duties, the visitor was in sight of at least five other badged licensee employees. There were no other visitors in the vital area. Additionally, EDG 2G002 was inoperable for the maintenance activity. The inspectors determined that little actual risk resulted from the failure of the escort to maintain the visitor within sight.

After the inspectors brought the occurrence to the attention of a licensee supervisor, the supervisor immediately briefed all the personnel involved with the maintenance activity, reminding them of the escorting requirements, and sent the visitor and escort out of the protected area. Security personnel interviewed the escort. Subsequently, the escort and visitor returned to their maintenance tasks.

The Physical Security Plan, Section 5.1.3, states that "visitors must be escorted at all times within the protected area by a card-key badged escort." Section 5.2.1.1 states that "all personnel who are not authorized unescorted access to the protected area are accompanied while in the protected area by an individual who has been granted unescorted protected area access and are limited to areas that they have a valid, work-related need to enter." This section also required that the escort be "able to maintain visual observation in order to detect any unauthorized activities." Section 5.2.2

states, in part, that "personnel escort requirements for vital areas are the same as those described in Section 5.2.1.1."

The failure of the escort to maintain visual observation of the visitor in a vital area was a violation of Section 5.2.2 of the Physical Security Plan. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (NCV 361; 362/99016-03). This violation was in the licensee's corrective action program as Action Requests 991100185 and 991100195.

c. Conclusions

A violation of Section 5.2.2 of the Physical Security Plan occurred when the inspectors identified that an escort failed to maintain visual observation of a visitor in a Unit 2 vital area. The presence of other badged personnel near the visitor, and the short duration of the occurrence, mitigated the significance of the violation; however, the violation was more than minor since it occurred in a vital area. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was in the licensee's corrective action program as Action Requests 991100185 and 991100195.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the exit meeting on December 10, 1999. The licensee acknowledged the findings presented.

The Nuclear Regulatory Affairs manager stated that the licensee would likely deny the noncited violation described in Section O2.1, "Locked Valves," of this report. The manager stated that the licensee did not consider that a valve locking device was required to provide evidence of unauthorized manipulation, but only required to prevent inadvertent operation. The manager stated that he was unable to determine that a regulatory basis existed to require valve locking devices to evidence unauthorized manipulation.

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

D. Brieg, Manager, Station Technical
J. Fee, Manager, Maintenance
J. Hirsch, Manager, Chemistry
R. Krieger, Vice President, Nuclear Generation
J. Madigan, Manager, Health Physics
D. Nunn, Vice President, Engineering and Technical Services
A. Scherer, Manager, Nuclear Regulatory Affairs
K. Slagle, Manager, Nuclear Oversight
T. Vogt, Units 2 and 3 Plant Superintendent, Operations
R. Waldo, Manager, Operations

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	On Site Licensing Event Report Review

ITEMS OPENED AND CLOSED

Opened and Closed

361; 362/99016-01	NCV	inadequate locking device (Section O2.1)
361; 362/99016-02	NCV	failure to maintain cable train separation (Section M8.1)
361; 362/99016-03	NCV	failure to perform escort duties (Section S1.1)

Closed

361; 362/1999-005-00	LER	loss of physical separation in the control room (Section M8.1)

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
EDG	emergency diesel generator
LCS	licensee-controlled specifications
NCV	noncited violation
NRC	U.S. Nuclear Regulatory Commission
PRA	probabilistic risk assessment
SR	surveillance requirement
STS	Standard Technical Specifications
TDAFW	turbine-driven auxiliary feedwater