ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-206/95-04
50-361/95-04
50-362/95-04

Licenses: DPR-13
NPF-10
NPF-15

Licensee: Southern California Edison Co.
P.O. Box 128
San Clemente, California 92674-0128

Facility Name: San Onofre Nuclear Generating Station, Units 2 and 3

Inspection At: San Onofre, San Clemente, California

Inspection Conducted: March 12 through April 22, 1995

Inspectors: J. A. Sloan, Senior Resident Inspector
J. J. Russell, Resident Inspector
D. L. Solorio, Resident Inspector
M. D. Tschiltz, Senior Resident Inspector (Diablo Canyon)
D. G. Acker, Senior Project Inspector
M. E. Murphy, Reactor Engineer

Approved: B.J. Olson for 5/25/95
H. J. Wong, Chief, Reactor Projects Branch F Date

Inspection Summary

Areas Inspected (Units 2 and 3): Routine, announced resident inspection of onsite followup of events, operational safety verification, maintenance and surveillance observations, engineering and plant support observations, followup on corrective actions for violations and deviations, other followup, and followup of licensee event reports.

Results (Units 1, 2 and 3):

Operations

The licensee's performance in Operations during this inspection period was adequate, but mixed. The inspectors noted generally adequate operator awareness of control boards, and noted that an operator appropriately questioned an indication that was different than expected (Section 3.2). Operators responded well to the loss of one stage of a reactor coolant pump (RCP) seal (Section 6.4). However, there were other instances in which

operators were not attentive to control board tags or indications, or did not adequately question indication changes.

Several errors were identified by the licensee and the inspectors earlier in the Cycle 8 refueling outage in Unit 2, and the trend continued in this inspection period.

- A violation was identified for two examples of inadequate procedures, one of which resulted in inadvertently draining from the reactor coolant system (RCS) (Section 3.5). The other example resulted in air-binding a low pressure safety injection (LPSI) pump (Section 3.4).

- On one occasion, the inspector found that operators did not understand caution tags on the control board (Section 3.1).

- On one occasion, operators did not notice that the indication for component cooling water flow had decreased to below the normal flow rate until identified by the inspector, and then took no action until an annunciator alarmed 30 minutes later (Section 3.1).

- Operators failed to coordinate activities resulting in a component cooling water pump being secured at almost the same time another operator was attempting to synchronize the bus the pump was powered from to the grid (Section 5.1).

- Operators inadvertently racked in the breakers for all three high pressure safety injection (HPSI) pumps while Unit 2 was in Mode 5 (Section 3.6).

- Operator knowledge appeared to be deficient regarding the ability to verify the inputs to the control element drive mechanism control system (CEDMCS) out-of-sequence annunciator. However, operator actions in response to out-of-sequence conditions were appropriate (Section 3.7).

The Operations management's response to the negative trend was good, in that the trend was recognized. An Operations standdown was conducted to try to address the performance deficiencies (Section 1.2).

Maintenance

Despite the large number of outage-related maintenance activities accomplished during this inspection period, the inspectors neither observed nor were aware of any significant problems. Observed performance was good, with the exception of one oversight in the integrated engineered safety features test procedure resulting in a test exception which should have been anticipated and could have been avoided (Section 5.1). Additionally, CEDMCS deficiencies present during the Unit 2 reactor startup were a distraction to the operators,

requiring operators to devote attention to understanding whether the system was functioning adequately to allow continuing rod withdrawal (Section 3.7).

Engineering

Engineering performance during this inspection period was generally excellent overall, characterized by active involvement in plant issues and thorough evaluation of conditions and problems:

- The Nuclear Oversight Division quickly got involved with a report of problems in the manufacture of nuclear fuel at the vendor's facility, and issued a stop-work order when dissatisfied with the vendor's handling of the matter (Section 6.3).

- Engineering promptly and thoroughly investigated a self-revealing failure of a reversing starter that prevented remote closure of a shutdown cooling (SDC) isolation valve, and appropriately consulted the vendor for assessment of proper maintenance (Section 6.2).

- Engineering aggressively evaluated the failure of the middle stage of an RCP seal. The assessments were reasonable based on the available information (Section 6.4).

- Engineering provided a thorough assessment of an eroded blowdown pipe in steam generator (SG) 2E088 (Section 6.7).

- Engineering adequately addressed the discovery that oversized lugs were improperly installed on switchgear wiring during original plant construction (Section 6.6).

- Engineering evaluated and supported the removal of a stuck fiber optic probe in SG 2E089 (Section 6.8).

- The licensee identified that the wrong addressable constants were installed in the Unit 3 core protection calculators (CPCs). An unresolved item was opened to address this (Section 6.5).

Some negative performance, mostly historical, was also observed:

- A violation was issued for inadequate corrective actions for resolving continuing performance deficiencies of Agastat Series 7000 relays (Section 9.2).

- The inspector identified that the operability assessment was imprecisely documented for one out of the 12 Cycle 8 refueling outage nonconformance reports (NCRs) reviewed (Section 6.1).

Plant Support

Performance in the Plant Support functional area during this inspection period was good. The licensee demonstrated good sensitivity to primary-to-secondary leakage by identifying a new small leak in Unit 3 and a significant tube plug leak in Unit 2 (Section 7.2).

Also during this period, several issues regarding leakage from the Unit 1 spent fuel pool (SFP) were investigated with the licensee and the inspector. The licensee's evaluation of conditions was thorough and appropriate (Section 2.1).

Summary of Inspection Findings:

- Violation 361/9504-01 was identified regarding two examples of inadequate procedures (Sections 3.4 and 3.5).
- Unresolved Item 362/9504-02 was opened to address installation of incorrect addressable constants in Unit 3 CPCs (Section 6.5).
- Violation 361/9504-03 was identified regarding inadequate corrective actions for continuing problems with Agastat relays failing to perform as required (Section 9.2).
- Violations 361/9424-01 and 361/9305-02 were closed (Sections 8.1 and 9.1).
- Followup Item 361, 362/9501-04 was closed (Section 9.2).
- Licensee Event Reports 361, 362/94-006 (Revision 0); 361, 362/94-002 (Revisions 0 and 1); and 361, 362/94-003 (Revisions 0 and 1) were closed (Sections 10.1 and 10.2).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Acronyms

DETAILS

1 PLANT STATUS (71707)

1.1 Unit 1

The unit was permanently shut down in November 1992 and placed in SAFSTOR.

1.2 Unit 2

The unit began the inspection period in Mode 6, with 90 fuel bundles loaded into the reactor core and its Cycle 8 refueling outage in progress. Mode 5 was entered on March 20, 1995. Mode 4 was entered on April 6, but licensee management decided to halt the plant heatup due to an inadvertent transfer of reactor coolant caused by operator error (see Section 2.2 and Special Inspection Report 50-361/95-06). Due to a number of operational events, the Operations Manager initiated a stop-work of operational activities on March 23, 1995, and held discussions with Operations crews. In addition, the Operations Manager held the same discussions with the other operational crews as they were scheduled to work. The unit was brought back to Mode 5 on April 7, 1995.

The unit again entered Mode 4 on April 8, and then entered Mode 3 on April 14. The unit entered Mode 2 and was critical on April 17 at 6:42 p.m.

Due to leakage (approximately 20 gallons per day) in a SG hot-leg tube plug, the licensee brought the unit back down to Mode 5 on April 20, 1995. The unit ended the inspection period in Mode 5, for repairs to the leaking SG tube plug.

1.3 Unit 3

The unit began the inspection period operating at essentially full power (97 percent). The unit operated at full power until March 19, 1995. Power was reduced to approximately 80 percent to facilitate bumping of a circulation water pump due to high condenser waterbox differential pressure (ΔP). Full power operation was resumed later that same day, and the unit operated at full power through the end of the inspection period.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 SFP Leakage - Unit 1

An inspection of the Unit 1 containment was performed in conjunction with the licensee's investigation into the potential flowpath of approximately 800 gallons of water that had drained from the SFP on April 10, 1995. A similar draindown also occurred on March 21, 1995, though the licensee thought then that the water had been transferred to the refueling water storage tank (RWST) through leaking isolation valves. During the inspection of the Unit 1 containment building on April 12, 1995, the licensee, accompanied by the

Senior Resident Inspector, unexpectedly found several hundred gallons of water in the reactor cavity, on the containment floor, and in the containment emergency and sphere sumps. Unit 1 was permanently shut down in November 1992.

The licensee determined that when the SFP water level was increased to 40 feet 10 inches, the SFP skimmer pump transferred water from the SFP to the upender cavity area of the SFP, and the unsealed transfer gate allowed the upender area level to increase slightly above the SFP level. Water apparently overflowed into a cable guide for the transfer trolley, filling the transfer tube, and leaked through the blind flange into the containment cavity. Corrective actions being evaluated by the licensee include tightening the bolts on the blind flange inside containment, plugging the cable guide tube, venting the seal of the transfer gate, and periodic monitoring of the containment cavity.

The NRC staff reviewed another SFP leakage issue in 1994 (NRC Inspection Report 50-206/94-23), to which the licensee responded with an action plan described to the NRC in a letter dated March 10, 1995. Approximately 2 gallons of water per week have been extracted from the area between the SFP liner and a water-proofing membrane from sampling wells. The licensee determined that this leakage was not solely from the SFP as earlier postulated. The licensee reached the conclusion that this water was diluted with nonradioactive water, possible ground water or condensation, because the tritium concentration was approximately half that in the SFP. The licensee postulated that due to pressure gradients, ground water may be seeping through the membrane into the sample area. The licensee concluded that SFP water was not getting into the ground water.

Additionally, the licensee determined that approximately 60 gallons per day (gpd) have leaked into the RWST from the SFP cooling system, and approximately another 70 gallons per day of water evaporate from the SFP. The licensee determined that the source of leakage into the RWST was leaking isolation valves. On March 21, 1995, the licensee tightened the isolation valves and determined that the leakage was stopped.

In summary, five leak mechanisms have been identified:

- SFP to RWST (60 gpd)
- SFP to containment building (2 occasions, approximately 800 gallons each)
- SFP to leakage detection area (less than 2 gallons per week)
- Nonradioactive water (unknown source) to leakage detection area (less than 2 gallons per week)
- SFP evaporation (70 gpd).

The inspector reviewed drawings of the SFP configuration and discussed with the licensee the potential for SFP water to be leaking to the groundwater. Based on these discussions, and on the licensee-observed dilution of the water in the leakage detection area, the inspector determined that the licensee had made a reasonable case that there was no evidence of leakage from the SFP leakage detection area to the groundwater, and that such leakage was unlikely.

NRC Headquarters, Region IV, and the resident inspectors participated in a conference call with the licensee on April 14, 1995. Based on the above activities and a walkdown of the SFP area by the inspector, the inspector concluded that the licensee's assessments were reasonable and that the licensee was taking appropriate actions to identify and evaluate the sources and consequences of leakage from the SFP.

2.2 Loss of RCS Inventory - Unit 2

At approximately 2:05 a.m. on April 6, 1995, 15 minutes after entering Mode 4 at the end of the Cycle 8 refueling outage, approximately 560 gallons of water were inadvertently transferred from the RCS to the RWST when operators failed to ensure that SDC suction isolation Valve 2HV9379 was closed before opening the LPSI pump mini-flow valve to the RWST. Pressurizer level decreased almost 10 percent in 2 minutes 10 seconds before operators reclosed the mini-flow valve. An NRC inspector responded to the site and determined that operators had stabilized the unit in Mode 4 and had recovered pressurizer level. The licensee then cooled the plant to Mode 5 to investigate the event and to repair Valve 2HV9379.

A special NRC inspection, documented in NRC Inspection Report 50-361/95-06, was conducted to assess operations performance issues.

The failure of Valve 2HV9379 to close is discussed in Section 6.2.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Operator Awareness of Control Board Indications

On April 7, 1995, while Unit 2 was in Mode 5 and the CPCs were not required to be operable, the inspector noted that the control operator (CO) did not understand the information on a caution tag on each CPC channel. The caution tag indicated that "safety valves" were inoperable, and the CO did not know whether that meant that main steam safety valves or pressurizer safety valves were inoperable. The caution tags had been on the control board since March 31, 1995. A cognizant engineer in the control room at the time clarified that the tags were related to main steam safety valves, four of which would be inoperable during lift setpoint testing in Modes 3 and 1. The inspector concluded that the operators should have been aware of the meaning of all tags on the control boards.

On April 17, 1995, while a reactor startup was in progress, the inspector noted that the control board indication for the component cooling water to

Critical Loop A return flow (2FI-6277) was reading significantly below the normal flow rate. The decrease was pointed out by the inspector to the control room operators who indicated that the instrument reading had decreased since it was last checked and that the instrument had been vented the previous day. Approximately 30 minutes later, the annunciator alarm for the low flow condition was obtained. Operators evaluated the condition, determined that startup could continue, and wrote a maintenance order (MO) to investigate the problem. The inspector noted that the operators took no action to resolve the indication problem prior to receiving the alarm.

The inspector also noted that the Unit 2 boronometer had a deficiency tag attached noting erratic operation of the indication. Subsequently, the inspector noted that the boronometer indication at the shutdown control panel did not have a similar deficiency tag, though it exhibited similar erratic behavior. The inspector reported this to the shift superintendent (SS), who initiated action to correct the discrepancy. The Operations Manager later stated that tags would not be placed at the shutdown control panel for problems already tagged in the control room. The inspector will review this practice in a future inspection.

Based on these observations, the inspector concluded that the operators were not being sufficiently attentive to control board indications and should have acted more promptly to address the flow indication problem pointed out by an inspector. The licensee acknowledged that operators should have been aware of these conditions.

3.2 Control Room Oversight

In response to an event on April 6, 1995 (see Section 2.2), the licensee issued a special order to emphasize the need for the SS to maintain oversight and not get so distracted or involved that oversight is lost. The special order also assigned Operations management personnel to maintain essentially continuous presence in the control room to provide backup to the SS and ensure that oversight was maintained. On April 8, 1995, several minutes before Unit 2 entered Mode 4, the inspector noted that both the SS and the management representative got distracted for about 5 minutes on an issue that did not require either of their attention (reviewing elementary drawings to determine if an annunciator should have reflashed, in order to determine if an MO should be initiated). During this time, the control room staff continued on with the plant heatup and valve manipulations to secure SDC.

The inspector also noted that the CO who initially noticed that the annunciator had not reflashed appropriately questioned the condition, which did not meet his expectation. The licensee determined that the alarm response procedure, which stated that the annunciator had reflash capability, was only partially correct, because the annunciator was designed to reflash under some conditions, but not under the condition observed. The inspector concluded that the CO's questioning attitude, and the SS's desire to resolve the question, were appropriate, but that the SS should have directed other

resources to resolve the problem or waited to a less critical time to review the drawings.

3.3 Draindown to Midloop Condition - Unit 2

On March 19, 1995, the licensee commenced draining the RCS to a midloop condition to remove SG nozzle dams and to work on a leaking charging system check valve. The inspector observed the activity from the control room and noted that procedural requirements were followed, control of the draindown was generally well performed (with one exception), and communications were clear and complete. In general, the inspector concluded that operators performed the activity well. However, the inspector noted a small problem at the start of the draindown, which was associated with SDC and letdown flow rates.

The exception occurred at the beginning of the draining evolution. Operators experienced difficulties obtaining the desired flow from the RCS through the chemical and volume control system (CVCS) to auxiliary building holdup tanks. Operators wanted to establish the letdown flow rate at approximately 100 gpm. In order to increase the flow, operators throttled the LPSI RCS injection valves in the closed direction to increase the flow resistance through the injection valves to force the water to the CVCS. At the beginning of the evolution, SDC flow had been approximately 2440 gpm. However, the throttling of the injection valves brought flow below the alarm set point of 2300 gpm, and operators responded to raise flow to the normal operating value of 2450 gpm. Operators throttled open the LPSI injection valves to increase the SDC flow rate. The inspector had been monitoring this evolution and noted that the plant monitoring system indicated that flow had decreased to as low as 2222 gpm. Subsequently, the inspector reviewed a computer printout of SDC flow trends during this evolution and determined that for a brief, transitory period, the flow rate appeared to decrease to slightly above Technical Specifications (TS) and the licensee's procedural limits for minimum flow rate (both 2200 gpm).

The inspector discussed the control of SDC flow rates with the Operations Manager. The Operations Manager stated that, in an effort to maintain the margin above the limits in an optimum manner, during subsequent draindowns operators would start at an initially higher flow rate so as to preclude coming so close to minimum flow limits. Several weeks later, the inspector observed the licensee commence another draindown to midloop evolution. Interviews with control room staff and a review of computer generated trends of SDC flow rates, both demonstrated that SDC flow was established at a higher rate prior to initiating the draindown. The inspector concluded that the licensee's corrective actions were effective.

3.4 Air Binding of LPSI Pump - Unit 2

On March 9, 1995, with the reactor defueled, operators aligned LPSI Pump 2P016 to the RWST to facilitate engineering surveillance testing. Shortly after the LPSI pump was started, it became air bound. Operators immediately stopped the pump and declared it inoperable. Engineering subsequently evaluated this

incident and determined that the pump was not damaged based on the pump subsequently having passed multiple inservice tests (ISTs) satisfactorily. The pump was declared operable. The inspector viewed the pump and did not identify any damage to the pump or related piping within the pump room. The inspector reviewed the licensee's evaluations and concluded they were appropriate.

The procedure used by operators to vent the LPSI pump was Procedure SO23-3-2.7, Temporary Change Notice (TCN) 8-41, "Safety Injection System Operation." Attachment 14, "Venting Emergency Core Cooling System (ECCS) Suction Piping After Maintenance," was the part of the procedure applicable for venting the LPSI suction piping. The procedure was performed because of a Train B ECCS clearance on multiple safety injection components which required that the suction piping to the HPSI, LPSI, and containment spray pumps be drained. The inspector reviewed the procedure used to vent the LPSI pump and determined that several vent valves at the suction of the pump were not included in the procedure. Subsequent to air binding the pump, the licensee vented the pump and air was removed from the pump for several minutes. Based on this evidence and the fact that two vent valves at the pump's suction were not in the venting procedure, the inspector also concluded that the pump had not been properly vented. While the licensee's formal evaluation of the incident had not been completed by the end of the inspection period, the licensee's preliminary view was also that the pump had not been properly vented. Overall, the inspector concluded that the procedure used for venting the LPSI was inadequate because it did not ensure that all of the entrapped air was evacuated from the LPSI pump. The inadequate procedure is the first example of a violation (Violation 361/9504-01).

The inspector interviewed an operator who had been on shift during the time the LPSI pump was run, and determined that guidance for venting of the LPSI pump had been contained in the past in the SDC system operations procedure. However, at the time of this activity, the guidance had been removed with the intent to place it in another Operations procedure. The inspector concluded that this could have contributed potentially to the event because without specific procedural guidance operators were forced to rely on a procedure which was not complete. In addition, the inspector determined that the SDC procedural guidance was not complete in that not all vents to the LPSI pump suction were included. As a result of this determination, the licensee was evaluating if previous attempts to vent the LPSI pump were affected by the vent valves which had not been previously included in the procedure. The inspector determined that at the end of the inspection period, the guidance for venting the LPSI pumps still had not been incorporated into the procedure; however, the licensee stated that a temporary instruction would be initiated if there was a need to vent a LPSI pump in the interim.

The inspector reviewed the work authorization record (WAR) which had controlled the Train B ECCS clearance and return-to-service of the LPSI and other safety injection components. Specifically, the inspector noted that the return-to-service requirements in the WAR specified that containment spray and HPSI procedures be used to return the ECCS suction piping to service. The

inspector interviewed the WAR evaluator and concluded that a detailed review of procedure against the piping and instrument drawings was not performed to conclude that all vent valves associated with venting of the LPSI were included. The inspector concluded that a thorough review of the procedure against the piping and instrument drawing would have identified that the procedure used was incomplete for the task of venting a LPSI pump.

The inspector also noted that the licensee had experienced several other problems with operation of ECCS pumps since late 1993, two of which resulted in damaged pumps. These problems resulted from weaknesses in procedural quality and adherence. Though adequate venting was not among the previous recent problems, the inspector concluded that a broader review of ECCS pump procedures following the other system alignment events might have ensured its adequacy for basic activities such as venting.

3.5 RCS Draindown - Unit 2

On March 21, 1995, shortly after placing a new CVCS letdown filter (F020) in service, control room operators noted that RCS inventory was decreasing. At the time, the unit was in Mode 5 with fuel in the core. The operators subsequently determined that the source of the leakage was from the letdown filter housing cover and isolated the filter, terminating the draindown approximately 25 minutes after discovery. Contributing to the time taken in stopping the draindown was the difficulty of access to the filter housing. The initial level was 1.22 feet below the top of the reactor vessel flange, and the final level reached was about one foot lower. The licensee's procedures considered that a reduced inventory condition was at 3 feet below the top of the flange. Ultimately, it was determined that the leak rate met the licensee's criteria for declaration of an Unusual Event.

The inspector interviewed operators involved in the activity and reviewed the Operations procedure for placing the letdown filter in service. The inspector concluded that, overall, control room operators did an excellent job of monitoring RCS levels because they noted the level decrease almost immediately after it had occurred and before any alarms were received for low or changing level. The inspector concluded, however, that the procedure for placing the letdown filter in service was not adequate for identifying leakage from the filter housing.

The inspector noted that Procedure SO23-3-2.1, TCN 12-35, "CVCS Charging and Letdown," provided the guidance used by operators to fill and vent the filter. After the filter was filled and vented using the nuclear service water (NSW) system, the procedure directed the operator to isolate NSW from the filter, and then inspect the filter housing for leaks through a 4-inch diameter lead-lined sight glass approximately 15 feet directly above the filter housing. The inspector concluded that, in the absence of NSW flow or pressure and the point of observation of the filter housing being at some distance and above the housing, leaks could not be easily identified. Such was the case for this incident. The inspector observed that for this reason the initial leak checks of the filter did not note any leakage. The inspector concluded

that the procedure used to align the letdown filter was inadequate because it did not provide an appropriate method to verify if the filter housing had leaks, and is the second example of a violation (Violation 50-362/9504-02).

Corrective actions taken by the licensee included modifying the Operations procedure to have operators maintain a pressure source, using NSW, to identify leakage. The inspector concluded that this action would be effective at identifying leakage and concluded overall that the licensee's corrective actions were adequate.

3.6 All Three Unit 2 HPSI Pump Breakers Simultaneously Racked-in While in Mode 5

On March 25, 1995, the licensee discovered, during performance of Procedure SO23-3-3.25.1, TCN 11-23, "Once a Shift Surveillance (Modes 5-6)," that all three Unit 2 HPSI pump breakers were racked in at the same time. Unit 2 was in Mode 5 at 105°F and 350 psia. TS 3.4.8.3.1 prohibits more than two HPSI pumps operable with the low temperature overpressure protection relief in service, and gives 8 hours to rack out the third breaker or shut the discharge valve so as to render one pump inoperable. The licensee racked out one of the HPSI breakers and initiated an Operations Division Event Report to determine why this happened.

The licensee informed the inspector of the discovery. The inspector interviewed cognizant Operations personnel and reviewed operating logs. The inspector and the licensee determined that at the beginning of the shift one HPSI breaker was racked in and its direct current (DC) control power energized. The other two pumps' breakers were racked out with DC control power off. After assumption of the shift, a second HPSI pump breaker was racked in so the pump could be used for an IST. Later, the third pump breaker was racked in to perform check valve testing. The initial IST was controlled by an abnormal alignment and the valve test controlled by an engineering procedure, neither of which addressed the breaker TS implications. The inspector determined that the condition had existed for approximately 2 hours and 45 minutes prior to being rectified, which did not exceed the 8-hour Limiting Condition for Operation time. The inspector also noted that DC control power was secured to these pumps for the latter portion of this time, such that pump start would have required local manipulations.

The inspector concluded that the licensee had adequately identified the root cause for this occurrence, which was the unit CO failing to recognize TS impact when he gave the order to establish conditions for the IST. This was despite the TS requirement having been discussed in the tailboard that preceded the evolution. The unit CO ordered that the HPSI pump breaker that had been racked in at the beginning of the shift have DC control power secured and did not order the breaker also racked out. The inspector noted also that the licensed operator who carried out this order failed to recognize the TS impact (he was not present at the tailboard). The inspector concluded that the licensee was taking appropriate actions to prevent recurrence by ensuring that all operators were trained on this TS, which had been changed such that

this outage was the first time it had been applicable. The licensee was also scheduling refresher training for all operators on all TS applicability while shut down. The inspector verified that the operators had been made aware of all TS changes through required reading and training conducted during preshift briefs. The inspector considered this adequate and will assess operator TS knowledge during the course of normal inspection activity.

3.7 Unit 2 Reactor Startup and CEDMCS Troubleshooting

The inspector noted that CEDMCS problems were experienced during the Unit 2 reactor startup on April 17, 1995. The inspector determined that some of these problems were identified by the licensee, but had not all been corrected, prior to the startup.

3.7.1 Background

The inspector observed from the control room portions of the CEDMCS testing performed by the licensee. CEDMCS problems were noted by the licensee during the initial withdrawal of control element assemblies (CEAs) in preparation for plant heatup. During CEA withdrawal, CEDMCS output traces were recorded to diagnose and evaluate CEDMCS problems. A total of 14 problems were noted during the review of the traces. Of these problems, 10 were fixed prior to commencing the startup, and the remaining four were evaluated by the licensee not impacting CEA operation, and, as such, did not require resolution prior to commencing the startup.

CEA rod drop time testing was subsequently performed in accordance with Procedure SO23-3-2.19, TCN 5-16, "CEDMCS Operation." During this testing, CEA 75 was noted to withdraw slower than other CEAs in its associated subgroup and required manual realignment with its associated group during withdrawal. The CEDMCS output traces had previously revealed that the coil driver for CEA 75 was missing a pull-down phase. This was initially evaluated as not effecting rod withdrawal. Following the rod drop testing, maintenance was not performed to correct the problem with CEA 75, nor the remainder of the deficiencies which were evaluated as not effecting the Unit 2 reactor startup.

During the CEA withdrawal for reactor startup in support of initial criticality testing, the rate of withdrawal for CEA 75 was reported to have been approximately half the rate of other CEAs in its group. This required the operators to perform a manual realignment of CEA 75 with its subgroup several times. As a result of the continuing problems with the withdrawal of CEA 75, the startup was suspended. The licensee then made the decision to further troubleshoot and correct the known CEDMCS deficiencies prior to accomplishing the startup.

Troubleshooting was performed by transferring the affected CEA subgroup to the hold bus and then replacing the suspected CEDMCS component. During the troubleshooting for CEA 72 and after replacement of the coil driver card shared by CEAs 69 and 72, the CEA subgroup was transferred back to CEDMCS control. A short time after this, the replacement coil driver card output for

CEA 69 malfunctioned, resulting in CEA 69 being dropped. The inspector observed that the operator response to the dropped CEA was appropriately performed in accordance with Abnormal Operating Procedure SO23-13-13, TCN 1-3, "Misaligned CEA." Following the second replacement of the coil driver card for CEAs 69 and 72, CEDMCS control of the affected CEAs was verified.

3.7.2 Problems During Startup

On April 17, 1995, the inspector observed portions of the performance of Procedure SO23-3-1.1 TCN 10-9, "Reactor Startup," for Unit 2. The procedure provided instructions for bringing Unit 2 from a hot standby condition to operation with reactor power stabilized.

During the CEA withdrawal sequence at several different points in the procedure, out-of-sequence alarms were received indicating that the difference in CEA height between the two groups of CEAs was less than 91.77 inches. Operators and shift management observed plant protection system parameters which indicated the CEAs appeared to be greater than the minimum differential and within the allowable band for the required height separation. It was later determined that evaluating the plant monitoring system output generated from CEDMCS pulses would have revealed that the height differential was at the 91.77 inches setpoint. CEA movement in manual individual control was used to align the CEAs which were the most out-of-alignment with other CEAs in the group to minimize the height differential. This action cleared the out-of-sequence alarm. Although the reason for the alarm was not fully understood, Operations shift management concluded that it was acceptable to continue since, by the monitored parameters, the out-of-sequence condition alarm occurred conservatively with greater than a 91.77 inches difference between the CEA groups. Later consultation with Engineering personnel indicated that the indication which showed the 91.77 inches differential was available to the operators; however, this information was not known by either the operators or the managers involved with the startup. The licensee initiated a procedure change to provide guidance to the operators regarding this issue.

3.7.3 Conclusions

Based on limited control room observations of the CEDMCS troubleshooting, the inspector concluded that the licensee's troubleshooting efforts were adequate to identify a number of deficiencies in the CEDMCS.

The inspector concluded that the CEDMCS deficiencies present during the startup were an unnecessary distraction to the operators, because the licensee could have corrected the identified deficiencies prior to the startup. The problems encountered during CEA withdrawal during the initial criticality startup required operators to devote attention to understand whether the system was functioning adequately to allow continuing rod withdrawal in each instance where CEAs were not withdrawing in sequence. The licensee considered its decision to defer maintenance on selected deficiencies to be reasonable and appropriate.

The inspector also concluded that the operators' lack of understanding of the ability to verify inputs to the out-of-sequence alarm appeared to be an operator knowledge deficiency, and the licensee's action to prevent recurrence was adequate. The operator actions taken to manually reposition individual CEAs within a group to clear the alarm appeared appropriate.

4 PLANT MAINTENANCE (62703)

During the inspection period, the inspector observed and reviewed selected documentation associated with maintenance and problem investigation activities listed below to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required quality assurance/quality control department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting.

Specifically, the inspector witnessed portions of the following maintenance activities:

Unit 2

- Troubleshooting and repair of CEDMCS due to loss of phase failures
- Safety Injection Tank Drain Valve 2HV9351 troubleshooting
- Troubleshooting CEDMCS problems

Unit 3

- Troubleshooting plant protection cabinet Channel A pressurizer low pressure setpoint

Based on the above observations, and on the absence of noteworthy maintenance-related deficiencies during this outage period, the inspector concluded that Maintenance performance was good.

5 SURVEILLANCE OBSERVATIONS (61726)

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

Specifically, portions of the following surveillances were observed by the inspector during this inspection period:

Unit 2

- SO23-3-3.12, Issue 2, "Integrated Engineered Safety Features (ESF) Test."
- SO2-V-3.12, "Integrated Leak Rate Test."
- SO23-5-1.3, Attachment 11, TCN 13-17, "Heatup Rate."
- SO23-3-3.31.9, Revision 0, "RCS Pressure Isolation Valve Testing."

5.1 Integrated ESF System Refueling Test

On March 27, 1995, the inspector observed this test from the Unit 2 control room and from the Train A Class 1E switchgear room. Overall, the inspector concluded that the test was performed satisfactorily, with the scope of the test being a strength. The scope of the test was good because the licensee tested actual ECCS equipment starts in response to a safety injection actuation signal and loss of voltage signal (LOVS) and had discovered problems in the past that may not have been discovered if the systems were tested on a piecemeal basis. The inspector had two comments:

- The inspector observed that the licensee was simultaneously securing loads and transferring the Class 1E buses back to offsite power sources after the main portion of the test was completed. The inspector noted that one operator announced securing a component cooling water pump, then another operator transferred the Class 1E bus to offsite power, then the first operator secured the pump. The inspector was concerned that there was no coordination of the two evolutions, and that if the pump had been secured at the same time that the emergency diesel generator was paralleled to offsite power, the frequency of the bus could have been raised, causing frequency of the oncoming power source to be slightly less than frequency of the running power source; consequently, inappropriate load relationships would result if the breaker would have shut. The inspector noted that automatic protection was installed to prevent this, but felt it should not be unnecessarily challenged. The licensee agreed to incorporate coordination of these activities in future integrated ESF tests.

- The inspector noted that the licensee received "lo-flow" alarms when attempting to shut SDC heat exchanger isolation valves from the component cooling water loop operating isolated from the noncritical loop, causing a test exception (an inability to test an actuation that had been planned to be tested). The inspector noted that a more thorough review of the test procedure would have identified this condition. The licensee indicated that a change would be made to the procedure.

The inspector considered these responses and the overall test were good. Agastat relays tested during this test are further discussed in Section 9.2 of this report.

6 ONSITE ENGINEERING (37551)

6.1 NCR Operability Assessment Review

The inspector selected 12 NCRs initiated between mid-February and mid-March 1995 and reviewed the operability assessments documented for the nonconformances. In most cases, the operability assessments were found to be soundly based and clearly documented. One exception was noted:

NCR 95020074 documented that the as-left closing torque (36 ft-lbs) for a motor-operated valve (Auxiliary Feedwater Pump 2P140 discharge to SG 2E089, Valve 2HV4705) exceeded the maximum allowed closing torque (31 ft-lbs). The operability assessment stated that the acceptance criteria was based on a 22-percent calculated inaccuracy for a 40 ft-lb calculated maximum closing torque, but that static test data indicated that a more accurate value was 11 percent, yielding a revised acceptance criteria of 36 ft-lbs. The inspector determined that 11 percent of 40 ft-lbs resulted in a 35.6 ft-lb maximum value, and that the as-left closing torque (36 ft-lbs) exceeded this maximum. The inspector noted that the licensee had concluded that the valve remained operable. The inspector determined in discussions with the licensee that the 35.6 ft-lb value had been rounded up to 36 ft-lbs in the operability assessment, and that the licensee had failed to document that approximately 18 percent additional margin existed in the setpoint calculations due to other overly conservative assumptions. The licensee acknowledged that the operability assessment should have been more explicit. The inspector noted that the NCR disposition required retesting and resetting the limit switches, and that this action would be completed before the unit completed the current refueling outage. The inspector concluded that the operability assessment could have been more precise, but that the licensee's actions were acceptable.

Overall, the inspector concluded that the operability assessments were reasonable and adequately documented.

6.2 Failure of SDC Isolation Valve 2HV9379

On April 6, 1995, motor-operated Valve 2HV9379 failed to close twice, blowing control power fuses each time. The licensee initiated NCR 95040017. The licensee determined that the failure was caused by a jammed mechanical interlock on the reversing line starter. The interlock was apparently jammed during performance of a preventive maintenance task to check the interlock function, and worn guide-holes in a sliding cam allowed the mechanism to jam. The licensee confirmed through testing that the solenoid core would not close with the interlock jammed, and that resulting current was sufficient to blow the 1-amp fuse. The inspector observed the jamming of the interlock during a bench demonstration, and concluded that the licensee's evaluation was reasonable.

The inspector determined, through discussions with the licensee, that the licensee had reviewed the maintenance procedure and vendor manual and had contacted the vendor to determine if the licensee's maintenance practice was appropriate. The vendor manual did not provide guidance on testing the mechanical interlock and, at the end of this inspection period, the licensee had not completed its evaluation of the maintenance practices.

The licensee had performed this same maintenance task on all similar Train A breakers. The licensee determined that nearly all of the affected components has been successfully operated since performance of the task, demonstrating that the mechanical interlocks did not jam. The licensee then tested the remaining affected components, with no problems identified.

The inspector determined that reportability per 10 CFR Part 21 was being considered by the licensee.

The inspector also determined that the licensee's preliminary root cause assessment and its efforts to ensure appropriate maintenance was performed were adequate. Additionally, the inspector concluded that the licensee's operability verification of other potentially affected components was appropriate.

6.3 Stop-Work Order Issued to Fuel Supplier

On March 29, 1995, the licensee's Nuclear Oversight Division issued a stop-work order to Combustion Engineering's (ABB/CE) fuel manufacturing facility, due to contaminants found on the surface of some fuel pellets manufactured for Unit 3 Cycle 8 fuel. The licensee dispatched inspectors to the manufacturing facility, and closely monitored ABB/CE's activities and required ABB/CE to assess the source and the potential impact of the contaminants on the fuel and cladding. ABB/CE determined that the contamination appeared to be lubricant from one of the fuel fabrication machines. The licensee contracted a consultant to independently review ABB/CE's assessment, and lifted the stop-work order after the consultant and the licensee were satisfied that ABB/CE had adequate addressed the cause and acceptability of operating with some contaminated fuel pellets. The inspector concluded that the licensee's response to the observed problems at the fuel manufacturing facility were appropriate.

6.4 RCP 3P004 Middle Seal Failure and Recovery

On April 11, 1995, the middle seal of the 4-stage seal package on RCP 3P004 failed, with ΔP decreasing to approximately 20 psid over less than one hour. The ΔP across the lower and upper stages increased in proportion to their ΔP extant before the event (the lower and upper stages had about 400 psid and 900 psid, respectively).

The inspector observed the control room indications and operator response, and determined that the licensee's assessment of the failure, and monitoring of the seal performance, was appropriate and consistent with licensee procedures.

Additionally, the inspector discussed the resultant condition of the RCP seal package with the licensee. The lower seal was known to be degraded, the middle seal was failed, and some spikes were observed on the upper seal. The vapor seal appeared to be fully functional. The inspector noted that each seal stage was designed to be capable of withstanding full RCS pressure, and that the abnormal operating instruction allowed continued operation with one stage failed (defined as less than 100 psid). Additionally, a controlled shutdown was required if a second stage failed. Through discussions with the licensee, the inspector determined that the licensee had verified, independently and by contacting the seal vendor, that the current seal configuration was acceptable for operation. The inspector noted that controlled bleedoff flow and temperature were acceptable.

The inspector determined that the seal had been in service only during the current fuel cycle, and that it was of an older design. The licensee stated that it intended to replace the seal with a new design, containing scalloped cooling channels on the seal surface, during the Cycle 8 refueling.

After the failure of the middle seal, the stage began to slowly reseal, developing about 100 psid over the first 24 hours, then rapidly resealing fully on April 13, 1995. The inspector verified that the ΔP for each stage was about the same as before the failure. The licensee determined that the most likely cause of the failure was some debris getting into the seal stage and working its way though the seal. The inspector discussed the possibility of the debris next interfering with the upper stage, and noted that because the cause of the failure was not fully understood, the licensee was continuing to closely monitor performance of the seals on RCP 3P004. The inspector noted that the seal performance was stable for the remainder of the inspection period.

The inspector concluded that the licensee's Engineering and Operations response to the seal failure was good.

6.5 Wrong Addressable Constants in Unit 3 CPCs

On March 31, 1995, with Unit 3 in Mode 1, the licensee discovered that the wrong rod-shadowing multipliers (addressable constants) were installed in the Unit 3 CPCs. The licensee installed the correct multipliers later that same day. The licensee determined that the multipliers were erroneous in a nonconservative direction, but that sufficient margin existed in the setpoints so as to remain in an analyzed condition.

Rod-shadowing multipliers were used to apply penalty factors to excore power (which inputs into the CPCs) to account for the effects of peripheral control rods that may be inserted and screen some of the neutron flux from the detector. Consequently, the excore power could be lower than actual power with certain rod insertion patterns. The multipliers installed were 1.022, 0.980, and 1.013 and the multipliers that should have been installed were 0.973, 0.983, and 0.972. Higher values were nonconservative because they

resulted in higher overall rod-shadowing factors, resulting in a lower excore power indication.

CEFAST is a software program used to verify CPC performance during initial startup, and ABB/CE provided constants, via letter, to be installed in this program as well as CPC constants for each core reload. In response to the initial discovery, the licensee contacted ABB/CE and was later sent a facsimile of a letter informing them that the CEFAST constants were actually correct for the CPCs, and that the CPC constants provided were wrong. The licensee noted, as a separate issue, that the CPC constants installed were not the ones provided, nor were they the CEFAST constants.

The inspector reviewed the correspondence from ABB/CE that stipulated the original erroneous constants and the CEFAST constants, as well as the licensee procedure and table used to install the constants that were actually installed. This item will remain unresolved pending inspector resolution of three issues:

- Review of safety significance;
- ABB/CE provided the wrong multipliers in a letter to the licensee. The inspector will determine any responsibility the licensee has to verify these numbers, either upon receipt or during power ascension testing, and, to the extent possible, why ABB/CE sent the wrong numbers; and,
- Different multipliers than those provided by ABB/CE were installed. The licensee apparently incorrectly transcribed the data from ABB/CE into tables provided to those who installed the constants, and did not identify the error despite multiple reviews.

The inspector will review results of a planned licensee division investigation report and conduct any additional inspection activity necessary to resolve the above issues and to determine if the licensee has taken sufficient actions to prevent recurrence (Unresolved Item 361/9504-02).

6.6 Wrong Size Electrical Lugs in Unit 2 Class 1E Switchgear

On March 15, 1995, licensee Maintenance personnel, performing an inspection of the Unit 2 Train B Class 1E 4.16 KV and 480 V switchgear, noted that one of the wires that was attached to the DC control power for a 4.16 KV breaker came loose from its lug as it was being inspected. The licensee determined that a lug for 10/12 gauge wire had been installed on 14-gauge wire, making the lug too big for the application. Lugs that are too big may not be securely fastened to the wire. The licensee contacted the vendor, ITE Imperial, and the lug manufacturer, AMP Incorporated, and inspected the remaining breakers in the Train B switchgear. The licensee replaced all wrong-sized lugs.

The inspector visually inspected the lug and portions of the Train B switchgear. The inspector noted that the switchgear was installed during

plant construction with the lugs as-found, that the lugs were color-coded such that they appeared to be the proper size, and that verification of size due to the location of size marking required rendering the particular breaker inoperable. The inspector also noted that the licensee had no history of problems with inoperable DC control power due to separation of the wire from the lugs. The licensee planned on inspecting the remaining Unit 2 train and both Unit 3 trains at the next opportunity.

The inspector considered that, since Maintenance personnel had noted the wrong sized lug was installed despite what appeared to be erroneous color coding, this was indicative of good attention to detail. The inspector considered the licensee's response to the observed condition was good.

6.7 Eroded SG 2E089 Blowdown Line - Unit 2

On March 18, 1995, while performing a close out inspection of SG 2E089, the licensee discovered that a vertical section of the 2-inch pipe connecting two elbows in the blowdown pipe had extensive erosion around 300° of its circumference. A hole was at the upper end of the pipe just upstream of the last elbow prior to exiting the SG. Because of the location of the eroded line the licensee could not easily make a repair. However, the licensee performed an interim evaluation for continued operation of the SG up through Mode 2 operations. The inspector reviewed the interim evaluation and had no concerns.

The long term operability of the SG, as well as the other SGs in Units 2 and 3, will be addressed as part of another operability evaluation which was not completed as of the end of the inspection period. The inspector will review the long term evaluation when it becomes available during routine inspection activities.

6.8 Fiber Optic Probe Lodged in SG 2E089 Tubes - Unit 2

On March 17, 1995, while performing mechanical cleaning of the Unit 2 SG E088 tubes, a small fiber optic cable became lodged in the SG. The cable became lodged when personnel were attempting to insert the mechanical cleaning device into the SG. The cable became lodged between several tubes located near the center of the SG. The licensee subsequently successfully removed the cable. The licensee performed an evaluation which concluded that the cable could not have damaged the tubes. The inspector discussed this evaluation with the licensee and concluded that the licensee's analysis was adequate.

7 PLANT SUPPORT ACTIVITIES (71750)

7.1 Radiological Controls

The inspectors verified by sampling that radiological postings and door controls were consistent with NRC requirements, and that licensee personnel were generally following licensee procedures for radiation protection.

Additionally, the inspectors reviewed radiation monitor traces and verified that there were no indications of uncontrolled releases.

7.2 Sampling and Chemistry

On March 28, 1995, the licensee noted that Unit 3 air ejector activity increased approximately one decade. Further analysis revealed that primary to secondary leakage had increased to approximately 0.5 gallons per day. The inspector concluded that the leakage was not significant and that the licensee's sensitivity to monitoring the leakage was excellent.

7.3 Physical Security

The inspectors observed protected area barriers, isolation zones, nighttime protected area illuminations levels, personnel access measures, package and material access measures, vehicles access measures, and visitor controls and determined that these security measures were adequate.

7.4 Emergency Preparedness

The inspectors observed that the onsite emergency response facilities were maintained in a state of readiness.

7.5 Fire Protection

The inspectors observed, on a sampling basis, that plant areas were free from inappropriate fire hazards, and fire protection equipment was functional.

8 FOLLOWUP - OPERATIONS (92901)

8.1 (Closed) Violation 361/9424-01: Control Room Senior Reactor Operator (SRO) Staffing

This violation was issued for the failure to maintain control room staffing levels of SROs in accordance with the requirements of TS 6.2.2. This event was identified by the inspector during backshift inspection activities. The inspector noted, however, that the period of time was brief, and that the SROs were within the control room envelope while they were outside of the TS-defined control room boundaries and could have responded to emergencies without significant delays due to their distance from the control room. The licensee stated that the cause of this event was an unclear understanding by SROs regarding the control room boundaries as defined in the TS. As a result, the SROs did not realize they had inadvertently stepped outside the TS-defined control room area. Based on observations and interviews with the SROs, the inspector concluded that the licensee's assessment was adequate.

As a result of this incident the licensee implemented the following corrective actions: made additional enhancements to the procedures promulgating shift manning requirements, revised the TS control room boundaries to reflect the current configuration, improved and added control room labeling/warnings, and

provided SROs with portable computers in the control room to alleviate the need for the SROs to leave the control room to access information systems necessary for operation of the units. The inspector reviewed these corrective actions through the course of routine inspections and noted additional formality displayed by SROs regarding shift manning requirements. The inspector concluded that the licensee's corrective actions should be effective in preventing recurrence.

9 FOLLOWUP - ENGINEERING (92903)

9.1 (Closed) Followup Item 361/9305-02: Seismic Testing of Leaking Batteries

This item was initiated based on the discovery of several leaking battery jar lids on two battery banks from Units 2 and 3 safety-related emergency batteries in March 1993. During installation of new Exide batteries the licensee discovered small leaks on several jars in two of the three battery banks replaced. The majority of the leaking batteries were replaced with the exception of Battery Bank 3D2, which was in service at the time of the discovery. The cause of the leaking jar lids was confirmed to be incomplete sealing of the lid to the jar. The licensee subsequently performed an evaluation which addressed postulated level losses for the batteries during a seismic event. The evaluation results indicated that the batteries with leaking jar lids would remain operable during a seismic event. Additionally, Exide, the battery vendor, provided the licensee with documentation confirming that the batteries would continue to function electrically during and after a seismic event. However, this item was initiated because the inspector noted that the documentation did not contain a justification for the assessment. In response to the inspector's concerns, one of the leaking cells was sent to the vendor for analysis of the cause of the seal problem between the jar lid and the jar. In addition, the licensee planned to conduct a seismic test of the two worst leaking battery jars.

The manufacturer ultimately determined that the cause of the minor leakage from the batteries was due to pinhole leaks which were created due to improper cementing during the manufacturing process. These pinhole leaks were not detected during the factory tests. The manufacturer also addressed the effects of chemical attack and thermal stress on the cement used to seal the jar lid to the jar, and concluded that the cement was resistant to chemical attack and thermal stresses. In addition, the licensee's seismic test of the two worst leaking batteries demonstrated that level losses due to the pin-hole leaks were minor. However, to provide complete assurance, the licensee committed to perform additional periodic inspections in accordance with the Institute of Electrical and Electronics Engineers Standard 450-1980. The additional inspections were incorporated into licensee procedures and were the following: (1) monthly visual inspection of the external casing of each cell for cracks and evidence of electrolyte leakage, (2) quarterly inspection of all cells for cell voltage, specific gravity, electrolyte level, and temperature, and (3) annual detailed physical inspection of each cell. The inspector reviewed these procedures and verified that the inspection criteria had been incorporated. On the basis of its tests and evaluation, as well as

the licensee's seismic tests of the leaking jar, the manufacturer determined that the batteries at Unit 3 would continue to perform their intended functions and would not experience physical or functional degradation from the jar-to-cover leaks throughout their 20-year nuclear qualified life.

These root cause, analysis of data, and compensatory actions were reviewed by the Office of Nuclear Reactor Regulation, which agreed with the manufacturer that the five battery jars with jar-to-cover leakage would perform their intended functions and would not experience physical or functional degradation from jar-to-cover leakage throughout their 20-year nuclear qualified life, provided the licensee conducted the additional periodic inspection, maintained the inspection log properly, and subsequent inspections did not reveal adverse findings.

9.2 (Closed) Inspection Followup Item 361/9501-04: Units 2 and 3 Agastat Relay Failure Rates

This unresolved item involved the inspector reviewing the last five year's worth of surveillance test data for Agastat Series 7000 pneumatically-operated relays. These relays were used to provide time delay of ECCS components as they automatically started in response to a safety injection signal, as well as providing delays during Class 1E electrical bus transfer during a loss of voltage. Units 2 and 3 had no master load sequencer for these functions. The inspector had previously noted a high rate of failure of these type relays while reviewing a licensee component failure analysis report. The inspector had also previously noted that NRC Information Notice 92-77 addressed failure rates of these relays at other plants and hardware changes that had been made.

The inspector reviewed as-found and as-left results of the time setting on Agastat relays tested during both Units' Cycle 6 and Cycle 7 integrated ESF (Procedure SO23-3-3.12, "Integrated ESF System Refueling Test") and LOVS (Procedure SO(2)3-II-11.1, "Safety Related LOVS and Sequencing Relay and Circuit Test") testing. The inspector also reviewed various NCRs and licensee evaluations and interviewed licensee personnel. The inspector also observed data gathering during the Unit 2 Cycle 8 integrated ESF testing and visually inspected numerous Agastat relays installed in both units.

The inspector found the following:

- The TS acceptance criterion for relay accuracy is ± 10 percent of load-group interval (TS Surveillance 4.8.1.1.2.13), vendor-stated accuracy is 10 percent of the setpoint at a constant temperature, and licensee procurement testing under seismic conditions revealed 12.5 percent of the setpoint. During a safety injection, load groups time-out from 0 seconds to 30 seconds (except emergency chillers which are set at 34 to 77 seconds) generally at 5 second intervals.

- LOVS testing was conducted prior to the integrated ESF testing for each outage, and each Agastat was individually checked. Fifty-two relays per

unit were tested. Overall, in the as-found condition, 18 percent of the relays were found to exceed the TS criterion for both units for both outages.

- Integrated ESF testing was conducted by initiating an ESF signal with a LOVS signal and measuring the time of breaker closure. Overall failure to meet the acceptance criterion was 27 percent (Cycle 6) and 39 percent (Cycle 7) with 32 relays per unit tested.

- Four percent of the relays failed to meet vendor accuracy, and of the relays set to 5 seconds, 14 percent failed to meet vendor accuracy.

- Sixty-six percent of the Agastat relay positions that failed the Cycle 6 testing failed the Cycle 7 testing. In one test, a 30-second set relay was slow by more than 7 seconds, using all margin in the allowed auxiliary feedwater start time.

- Failure rates since the units have been in operation (approximately 12 years) were essentially the same as described above.

The inspector also noted the following history of licensee response:

- The licensee had requested that the original TS allow 10 percent of interval, but this request was rejected.

- In 1987, the NRC raised questions about the high failure rate and the licensee performed an analysis to show that load groups and diesels remained operable.

- In 1992, the licensee initiated an NCR in response to Information Notice 92-77. The NCR led to an analysis that demonstrated that the emergency diesel generator could start two load groups simultaneously, and that systems would still function in terms of flowpath if two load groups started simultaneously. The licensee planned on performing a Final Safety Analysis Report (FSAR) analysis and submitting a request to change TS, which had not been completed at the end of this inspection.

- During this inspection, the NRC again questioned operability. The licensee addressed FSAR assumptions and determined that they were satisfied.

- For individual Agastat relay failures, the licensee would generate an NCR only if the Agastat relay was unable to be successfully recalibrated, unless the as-found timing setting appeared far out of specification. The 7-second Agastat relay mentioned above resulted in an NCR. The NCR specified that the Agastat relay go to the licensee's Independent Safety Engineering Group for root cause analysis. No deficiencies were noted.

Based on the above, the inspector concluded that no instances were noted where an Agastat timed out beyond assumed FSAR times. However, the inspector considered that failure rates for those Agastat relays at the 5-second and 30-second intervals were excessively high. The inspector also concluded that the licensee had not been effective in addressing a performance trend that spanned several years and was generally slow in documenting assessments concerning the safety significance of Agastat failures, until prompted by the NRC. 10 CFR Part 50, Appendix B, Criterion XVI, states that significant conditions adverse to quality such as deficiencies and failures shall be assessed so as to determine their cause and to preclude their recurrence. The high repetitive failure rates of the Agastat relays to meet the TS acceptance criterion and the licensee's failure to prevent this repetition by either performing an evaluation and submitting a TS change, or making hardware changes, or a combination of the both, is a violation of this requirement (Violation 361/9504-03).

10 ONSITE REVIEW OF LICENSEE EVENT REPORTS (LERs) (92700)

The following LERs were closed through direct observation, discussion with licensee personnel, or review of the records:

10.1 (Closed) LER 361, 362/94-006, Revision 0: Violation of TS 6.2 Shift Manning

This LER was submitted because of a brief period of time in which there were no SROs in the Unit 2/3 control room area, as defined in the licensee's TS. On October 23, 1994, the inspector identified that there were no SROs in the Unit 2/3 control room area, as defined in the licensee's TS, while both units were at full power conditions. The inspector reviewed this LER as part of the review of Violation 361/9424-01 (See Section 8.1).

10.2 (Closed) LER 361, 362/94-002, Revisions 0 and 1, and 361, 362/95-003, Revisions 0 and 1: Missed Fire Protection Surveillances

The licensee determined that it had missed TS-required fire protection surveillances and issued LERs 94-02, Revisions 0 and 1, and LER 94-03, Revision 0. Based on these LERs the licensee determined that additional actions were necessary to resolve the problems. The licensee issued LER 94-03, Revision 1, on January 17, 1995, to document the additional actions.

The licensee stated that a number of fire protection TS surveillances had been missed. The licensee determined that the primary cause for the omissions was due to personnel errors and lack of management oversight. The licensee had made a number of revisions to fire protection procedures. During these procedure revisions a number of required surveillances were deleted. In some cases, the error occurred when repetitive MOs were not updated to include new procedure requirements. The licensee completed the missed surveillances and performed a 100 percent review of TS fire protection requirements. The licensee stated that it had confirmed that TS-required fire protection

surveillances had been completed. The licensee added administrative controls to its program.

One of the licensee's corrective actions was a complete Nuclear Safety Group audit of the TS fire protection program, Audit Report SCES-446-94, "TS Fire Protection Audit," dated December 1994. The audit concluded that the licensee was in compliance with the TS.

The inspector reviewed the licensee's audit, reviewed sample TS surveillance data, and walked down systems to verify that the surveillances covered the installed equipment. In addition, the inspector randomly selected installed fire protection equipment in the Unit 3 radwaste building 63-foot elevation south cable gallery and diesel generator rooms and verified that the installed equipment was not damaged, that it matched system plans, and that it had been adequately tested or inspected.

During review of licensee surveillances the inspector noted that the licensee was identifying and documenting potential differences between installed equipment and plan requirements.

The inspector did not identify any installed TS fire protection equipment that was defective or had been missed by surveillance procedures. Based on the inspector's sample review and the 100 percent Nuclear Safety Group audit, the inspector concluded that the licensee's actions were adequate to resolve these LERs.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel.

*D. Breig, Manager, Station Technical
C. Chiu, Manager, Quality Engineering
*J. Fee, Maintenance Manager
*T. Frey, Engineering Aide, Onsite Nuclear Licensing
G. Gibson, Supervisor, Onsite Nuclear Licensing
*R. Giroux, Licensing Engineer, Onsite Nuclear Licensing
D. Herbst, Manager, Quality Assurance
*M. Herschthal, Manager, Nuclear Systems Engineering
P. Knapp, Manager, Health Physics
R. Krieger, Vice President, Nuclear Generating Station
*W. Marsh, Manager, Nuclear Regulatory Affairs
H. Newton, Manager, Site Support Services
*G. Plumlee, Lead Licensing Engineer, Onsite Nuclear Licensing
J. Reeder, Manager, Nuclear Training
J. Reilly, Manager, Nuclear Engineering & Construction
*R. Rosenblum, Vice President, Nuclear Engineering and Technical Support
*M. Short, Manager, Site Technical Services
*K. Slagle, Manager, Nuclear Oversight
*A. Thiel, Manager, Electrical Safety Engineering
T. Vogt, Plant Superintendent, Units 2/3
*R. Waldo, Operations Manager
M. Wharton, Manager, Nuclear Design Engineering
W. Zintl, Manager, Emergency Preparedness

1.2 NRC Personnel

*J. Russell, Resident Inspector
*J. Sloan, Senior Resident Inspector
*D. Solorio, Resident Inspector
*T. Reis, Project Engineer

1.3 Other NRC-Sponsored Personnel

*W. Kim, Inspector, Korea Institute of Nuclear Safety
*D. Korosec, Inspector, Slovenian Nuclear Safety Administration

In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

*Denotes personnel that attended the exit meeting.

2 EXIT MEETING

An exit meeting was conducted on April 24, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

ACRONYMS

ΔP	differential pressure
ABB/CE	Combustion Engineering
CEA	control element assembly
CEDMCS	control element drive mechanism control system
CO	control operator
CPC	Core Protection Calculator
CVCS	chemical and volume control system
DC	direct current
ECCS	emergency core cooling system
ESF	engineered safety features
FSAR	Final Safety Analysis Report
HPSI	high pressure safety injection
IST	inservice test
LER	Licensee Event Report
LOVS	loss of voltage signal
LPSI	low pressure safety injection
MO	maintenance order
NCR	nonconformance report
NSW	nuclear service water
RCP	reactor coolant pump
RCS	reactor coolant system
RWST	refueling water storage tank
SDC	shutdown cooling
SFP	spent fuel pool
SG	steam generator
SRO	senior reactor operator
SS	shift superintendent
TCN	temporary change notice
TS	Technical Specifications
WAR	work authorization record