U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report: 50-529/93-14

Docket: 50-529

License: NPF-51

Licensee: Arizona Public Service Company
P. O. Box 53999, Station 9012
Phoenix, AZ 85072-3999

Facility: Palo Verde Nuclear Generating Station
Unit 2

Inspection Location: Wintersburg, Arizona

Inspection Duration: March 17-25, 1993

Approved By: Stt Ad For 4-15-93
K. E. Perkins, Director Date Signed
Division of Reactor Safety and Projects

Team Leader: D. F. Kirsch, Technical Assistant, Division of Reactor Safety and Projects (DRSP), Region V

Administrative Assistant: D. Riley, Region V

Team Members: R. Bocanegra, Radiation Specialist, Region V
G. Galletti, Human Factors Engineer, NRR
K. Ihnen, Operations Engineer, Region I
K. Karwoski, Materials Engineer, NRR
W. Lyon, Senior Reactor Engineer, NRR
P. Qualls, Reactor Inspector, DRSS, Region V
T. Sundsmo, Reactor Inspector, Region V

Areas Inspected:

A special announced Augmented Inspection Team (AIT) inspection was performed to determine and evaluate licensee activities and circumstances related to the March 14, 1993 steam generator tube rupture event at Palo Verde, Unit 2.

The AIT used NRC Inspection Procedure 93800 and the AIT charter (provided as Appendix B).

General Conclusions and Findings:

Overall, the AIT found that the licensee succeeded in bringing the unit to a cold shutdown condition and limiting the release of radioactivity such that no threat to public health and safety occurred. However, the AIT identified several areas of weakness regarding the licensee's response to the event.

The AIT's primary findings focussed on the effectiveness and use of the Emergency Operating Procedures (EOP) and the Emergency Plan Implementing Procedures (EPIP).

In the area of the EOPs, the licensee has implemented the Diagnostic Logic Tree which examines specific plant conditions at the instant in time at which the decision point is reached, without accounting for recent plant conditions or trends in those conditions. Specifically, in the case of the Unit 2 Steam Generator Tube Rupture (SGTR) event, this consideration of only extant conditions caused the operators to misdiagnose the event two times and subsequently enter the Functional Recovery Procedure. This contributed substantially to the delay in isolating the faulted steam generator.

In the area of the EPIPs, the procedures do not differentiate between a SGTR event and a small break loss of coolant (SBLOCA) event. NRC guidance in NUREG-0654 would provide that a SGTR event be classified as an Alert if it were treated separately from a SBLOCA in excess of makeup capacity. The licensee's EPIPs classify a SGTR event at a more serious classification level (Site Area Emergency) than NRC guidance would require.

The AIT identified several instances where procedures were not fully implemented as specified. Specifically:

- The event was not classified in accordance with Emergency Plan Implementing Procedures because the fact that the inventory loss from the Reactor Coolant System had exceeded the charging pump makeup capacity was not properly entered into the EPIP checklist.

- The Emergency Operations Facility and the Technical Support Center were activated in 1 hour 40 minutes and 1 hour 43 minutes, respectively, instead of the one hour goal provided by procedures.

- Assembly and accountability completion occurred 6 hours 44 minutes after being called for instead of the 30 minutes required by procedures. Further, no list of personnel, by name, was provided to the Emergency Coordinator listing the names of personnel unaccounted for, as required by procedure.

- The Emergency Response Data System was activated 1 hour 10 minutes after the Alert was declared instead of within 1 hour, as required by 10 CFR 50.72.

- The Condenser Vacuum Pump Exhaust Radiation Monitor was found to have a problem about 1 week prior to the event, which later made the monitor inoperable. There was no action taken to further evaluate the problem. This represents a missed opportunity to have corrected an indication which may have aided the operators diagnosis of the event.

- A Radiation Monitoring System technician performed an alarm setpoint change on the Waste Gas Area Combined Ventilation Exhaust monitor without first obtaining the required prior approvals.

- A Radiation Monitoring System technician did not fully implement alarm response procedure requirements when notified of an alarming condition on the Main Steam Line Radiation monitor.

- Security personnel did not check the Owner Controlled Area (OCA) at the time of accountability as required by procedure, due to an insufficient security staff, onsite at the time of the event, to accomplish that function.

Significant Safety Matters:

A steam generator tube rupture is a safety significant event; however, the plant was successfully brought to cold shutdown and no radioactivity was released off site.

Strengths Noted:

The AIT identified the following licensee strengths in responding to the event:

- The operators took timely action to limit the consequences of the event, in accordance with their procedures, such as:

    - Securing the correct Reactor Coolant Pumps to maintain pressurizer spray

    - Placing the Atmospheric Dump Valve controllers in Manual to prevent release of contaminated steam to the environment

    - Placing the Condenser Hotwell level makeup/dump controller in Manual to prevent dumping contaminated condensate to the Condensate Storage Tank

- Filling both steam generators to near 80% to assure partitioning of radioactive coolant entering the steam generator

- When the licensee staffed the TSC and EOF, these facilities were staffed with more than adequate numbers of highly qualified people.

Weaknesses Noted:

The AIT identified several weaknesses, specifically:

- The Alert and Alarm setpoints of the Condenser Vacuum Pump Exhaust and Main Steam Line radiation monitors appear to have been based upon off-site dose limits rather than the ability to provide a reliable and timely indication of a SGTR event, as suggested by NRC Information Notices 88-99 and 91-43.

- In the simulator the above alarms occur within about 2 to 3 minutes of a SGTR event, which was different than the control room indications during the Unit 2 event. This represents a negative training situation for the operators.

- The plant staff in Units 1 and 3 did not fully respond to the assembly notification and many called their control room to inquire whether the call to Assembly applied to them. This contributed to the inability to complete accountability in the required time.

- The licensee observed an abnormal amount of crack growth in a steam generator tube during unit 2 refueling outage 3, and did not perform a formal evaluation of the safety significance of the observation. This represents a weakness in the performance of technical work.

- Weaknesses were observed in the operator training program, which appear to be examples of negative training. Specifically:

    - Alarms on the Condenser Vacuum Pump Exhaust and/or the Main Steam Line radiation monitor occur in the simulator SGTR training scenarios within about 2 to 3 minutes of a SGTR event, which was different than the control room indications during the Unit 2 event.

    - Small steam release pathways, such as the Unit Auxiliary Steam Relief line, are not adequately addressed in simulator exercises or classroom training.

    - The simulator and plant control board High Pressure Safety Injection flow indications do not indicate flow below an RCS pressure of about 1800 psia and training does not discuss the possibility that flow will occur at pressures up to about 1860 psia.

TABLE OF CONTENTS

A. Introduction - Formulation and Initiation of the AIT

1. Background and Formation of AIT............... 1
2. AIT Inspection Plan - Initiation of Inspection 1
3. Persons Contacted........................... 1

B. Description of Unit 2 Event

1. Event Summary................................ 1
2. Detailed Sequence and Chronology.............. 2

C. Licensee Response to Event

1. Operator Performance......................... 6
2. Equipment/System Performance................. 13
3. Emergency Operating Procedure Use and Adequacy 18

D. Licensee Emergency Plan Implementing Actions

1. Classification.............................. 20
2. Notification................................ 23
3. Staffing.................................... 23
4. Information Updates......................... 24
5. Emergency Response Coordination............. 24
6. Licensee Investigation Actions.............. 24
7. Conclusions................................. 25

E. Human Performance Evaluation

1. Training.................................... 25
2. Human System Interface...................... 28
3. Command, Control, and Communications........ 29
4. Staffing.................................... 30
5. Conclusions................................. 31

F. Radiological Consequences...................... 32

G. Radiation Monitoring System.................... 34

H. Security Consequences.......................... 37

I. Assessment of Steam Generator History

1. Steam Generator Design...................... 40
2. Steam Generator Inspection Results.......... 40
3. Evaluation of Degradation Mechanisms........ 44
4. SG Inspections 54
5. Outage Plans................................ 55
6. Hydrogen Control............................ 58

J. Exit Interview.................................... 59

Appendix A: Persons Contacted

Appendix B: AIT Charter

LIST OF ACRONYMS

AIT	Augmented Inspection Team
AO	Auxiliary Operator
APS	Arizona Public Service Company
APSS	Auxiliary Pressurizer Spray System
Asst SS	Assistant Shift Supervisor
CIAS	Containment Isolation Actuation System
CRDR	Condition Report/Disposition Request
CRS	Control Room Supervisor
CS	Containment Spray System
CST	Condensate Storage Tank
EAL	Emergency Action Level
EC	Emergency Coordinator
EER	Engineering Evaluation Request
ENS	Emergency Notification System
EOC	Emergency Operations Center
EOD	Emergency Onsite Director
EOF	Emergency Operations Facility
EOP	Emergency Operating Procedure
EPIP	Emergency Plan Implementing Procedure
ERDS	Emergency Response Data System
ERF	Emergency Response Facility
ERFDADS	Emergency Response Facility Data Acquisition and Display System
HPN	Health Physics Network
HPSI	High Pressure Safety Injection
LCO	Limiting Condition for Operation
LPSI	Low Pressure Safety Injection
MST	Mountain Standard Time
NUE	Notification of Unusual Event
OCA	Owner Controlled Area
PA	Protected Area
PVNGS	Palo Verde Nuclear Generating Station
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
SAE	Site Area Emergency
SIAS	Safety Injection Actuation System
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SS	Shift Supervisor
STA	Shift Technical Advisor
STSC	Satellite Technical Support Center
TBD	Technical Basis Document
TDAS	Temporary Data Acquisition System
TEC	Technical Engineering Coordinator
TRO	Tertiary Reactor Operator
TS	Technical Specification
TSC	Technical Support Center
VP	Vice President

NOTE: All times are given in Mountain Standard Time.

A. Introduction - Formulation and Initiation of the AIT

1. Background and Formation of AIT

On Sunday, March 14, 1993, at 0502, MST, following the rupture of a tube in SG-2, Palo Verde Unit 2 declared an ALERT. The unit had been operating at about 99% power prior to the event when, at about 0435, the operators observed pressurizer level and pressure decreasing, and subsequently tripped the unit.

The potential for significant generic implications of this event suggested the need for further evaluation by an NRC AIT. On the afternoon of Sunday, March 14, 1993, after detailed regional and resident staff briefings and consultation with senior NRC Headquarters management from NRR and AEOD, the Region V Acting Regional Administrator directed the dispatch of an AIT.

2. AIT Inspection Plan - Initiation of Inspection

The AIT Charter (included as Appendix B to this report), including the inspection plan, was prepared by the Region V staff and promulgated by the Regional Administrator on March 15, 1993. The AIT members arrived at PVNGS on March 14-16, 1993. To initiate the special inspection, an entrance interview was held with licensee management on the morning of March 17, 1993.

3. Persons Contacted

Refer to Appendix A.

B. Description of Unit 2 Event

1. Event Summary

On March 14, 1993, at about 0435, with Unit 2 operating at about 99% power, the operators observed pressurizer pressure and level decreasing. In response, they started the third charging pump and isolated reactor coolant system letdown at 0437. Pressurizer level and pressure continued to decrease and the operators manually tripped the reactor at 0447, at which point pressurizer level was slightly less than 25%. At 0448, Safety Injection and Containment Isolation Actuation Signals were automatically initiated at 1837 psia. Reactor coolant pumps 1B and 2B were stopped, the B main feedwater pump turbine was tripped, and one economizer isolation valve per steam generator was closed. All ESF equipment actuated as required.

An UNUSUAL EVENT was declared at 0458, due to the SIAS and CIAS actuation. The licensee upgraded the emergency classification to an ALERT at 0502, based upon the operator's observation of RCS leakage greater than 44 gpm.

After the unit tripped, pressurizer level decreased to less than 0% indicated level and remained less than 0% for about 1.5 minutes until HPSI brought the level up to about 8%. Analysis of the pressurizer pressure graphs determined that the pressurizer did not empty. The minimum pressurizer pressure reached, upon reactor trip, was 1687 psia. The operators entered the action statement for LCO 3.4.4 on SG-2 for a tube rupture at 0552. After the trip, pressure recovered to about 1900 psia and remained in that vicinity until cooldown and depressurization was commenced at about 0603. The goals of this cooldown and depressurization were to achieve a temperature and pressure of about 545° and 1500 psig, and to restore pressurizer level with HPSI. The operators continued the cooldown at 0721 and isolated SG-2 at 0728. Unit 2 entered Mode 4 at 1029. The operators secured the Reactor Coolant Pumps and placed the plant on shutdown cooling Train A at 2235 on March 14, 1993.

The unit entered Mode 5 at 0556 on March 15, 1993. The ALERT was terminated at 0115 on March 15, 1993 after the Emergency Operations Director assured that Shutdown Cooling Train A had been satisfactorily walked-down and the operators were confident in their ability to maintain stable plant conditions and system operation.

2. Detailed Sequence and Chronology

DATE/TIME	EVENT
March 14, 1993	
pre-event	Pressurizer level = 48% in automatic control; Pressurizer pressure = 2225 psia in automatic control; Reactor power = 98.8% (CR Log).
0025	Gas stripper was placed in service to degas the RCS.
0434:37	SG#2 tube rupture initiated at approximately 250 gpm (TDAS), without leak before break conditions. Radiation monitor RU 140 (SG 2 main steam line monitor) alarmed (RMS Alarm Typer).

0435	Operators initially observed pressurizer pressure decreasing at 27 psia/minute; Pressurizer level initially dropping at 3% per minute (TDAS).
	Radiation monitor RU-7 (Auxiliary Steam Condensate Receiver Tank Radiation Monitor) alarmed (CR Log, RMS Alarm Typer).
0437	Operators energized pressurizer backup heaters manually, started the third charging pump, and isolated letdown (Unit Log, CR Log, Alarm Typer).
	Pressurizer level was 42% and continued to steadily decrease at 1.5%/minute until the reactor was tripped (TDAS).
0438	Pressurizer low pressure alarm - 2159 psia (Alarm Typer).
0447	Pressurizer low level alarm - 25%; pressurizer heaters automatically deenergize (Alarm Typer).
0447	Manual reactor trip. Just prior to the trip, pressurizer level was at 25% decreasing steadily, pressure was at 2139 decreasing at 15 psia/minute (TDAS); Pressurizer level decreased to less than zero after the trip, but did not empty (Unit Log, CR Log, TDAS).
0448	Automatic SIAS and CIAS initiated; all ESF equipment actuated as required. RCPs 1B and 2B were manually stopped. SG blowdown radiation monitors (RU-4 and 5) isolate on CIAS (Alarm Typer, CR Log, Unit Log).
0448:43	Main Steam Line radiation monitor alarms clear (RMS Alarm Typer).
0449	Pressurizer level stabilizes at around 8% with HPSI injecting between 50-100 gpm, level slowly increases to 11% between 0449 and 0611; Pressurizer pressure stabilizes near the HPSI shut off head, at about 1885 psia during this period (TDAS).
0458	NUE declared (Unit Log).

0502	ALERT declared (Unit Log); operators enter functional recovery procedure because event diagnosis was unsuccessful.
0514	Local officials notified of event. Charging Pump E trips on low suction pressure (Alarm Typer).
0520	Unit 1 Shift Supervisor assumes Emergency Coordinator duties (Unit Log). Assembly is called for (Security Log).
	RU-4 and 5 are returned to service.
0529	RU-5 SG Blowdown Radiation Monitor alarms (RMS Alarm Typer).
0530	NRC notified of event via ENS.
0531	RU-141 (Condenser Air Removal Radiation Monitor) alarms intermittently (RMS Alarm Typer).
0534	RU-4 SG Blowdown Radiation Monitor Alarms (RMS Alarm Typer).
0538	Auxiliary Feedwater Pump P001 started and used to feed SGs (Alarm Typer).
0543	Stopped LPSI and CS pumps (CR Log).
0551	Charging suction shifted to CH-V327 (Alarm Typer)
0551	Accountability of personnel on-site was requested (Security log).
0603	Commenced cooldown per Functional Recovery Procedure (Unit Log, CR Log).
0604	Commenced depressurization to 1500 psia (CR Log, TDAS).
0611	HPSI used to increase Pressurizer level (Unit Log).
0612	ERDS Activated (ERFDADS Computer Printout).
0624	Operators exit Functional Recovery Procedure after restoring pressurizer level to above 33%, re-enter diagnostic (Unit Log, Alarm Typer).

0630	HPSI B throttled (CR Log).
0635	Stopped HPSI B (CR Log).
0640	SGTR diagnosed (Unit Log).
0642	EOF activated (ENS Log).
0645	Operators entered SGTR procedure (CR Log). TSC activated (TSC Log).
0652	TSC activated (ENS Log).
about 0700	Auxiliary steam system relief valve supplied by Unit 2 reportedly lifts (Operator Interviews).
	Operators conducted shift turn-over; oncoming crew continues in SGTR Procedure.
about 0720	Auxiliary steam system relief valve isolated (Operator Interviews).
0721	Re-initiated RCS cooldown per SGTR procedure (CR Log).
0728	SG-2 isolated (Unit Log).
0804	Unit 2 Auxiliary steam shifted to Unit 3 supply (CR Log).
about 0815	RCS pressure reduced to within 100 psid of SG#2 pressure.
0910	Personnel accountability reported; 54 people were identified by badge number as within the protected area, but were not accounted for.
1029	Unit 2 entered Mode 4 (Unit Log).
1133	SIAS and CIAS were reset (Unit Log).
1204	Accountability of personnel on-site completed (Security Log).
1430	EDG A was manually shutdown (ENS Log).
1515	EDG B was manually shutdown (ENS Log).
1606	Safety Injection Tanks were isolated (Unit Log).

1637 Completed SG tube rupture procedure (STA Log) and entered the normal shutdown procedure.

2235 Shutdown cooling Train A placed in service (STA Log).

March 15, 1993

0115 Terminated ALERT (STA Log).

0556 Unit 2 Entered Mode 5 (CR Log).

C. Licensee Response to Event

1. Operator Performance

The AIT reviewed documentation and conducted interviews with personnel involved with the event response and recovery. Personnel interviews included the shift supervisor, assistant shift supervisor, reactor operators (primary, secondary, and third RO), shift technical advisors, and other members of the plant staff.

The rapid decrease in pressurizer level and pressure were quickly assessed by the operators. Initial diagnosis was initially complicated due to other operational events that had been occurring. Placement of the gas stripper in service earlier in the shift raised the possibility of an inter-system LOCA due to a possible gas stripper heat exchanger tube leak. Recent problems with turbine load control and the possibility of a load rejection were considered. An elevated pressurizer relief valve tailpipe temperature, due to previously existing leakage, made the operators consider a stuck open pressurizer relief valve. Recent steam generator tube leaks also raised the possibility of a steam generator tube rupture.

Operator interviews identified that the crew observed multiple indications of the key plant parameters, that were needed to evaluate plant status, within 1 to 2 minutes after decreasing pressurizer level and pressure were first identified. Because of previous problems with the main generator voltage regulator, the Third Reactor Operator immediately checked turbine load, and informed the other operators that load was steady. RCS temperature indications (Tcold) were confirmed to be stable. Decreasing pressurizer level and pressure were verified and closely monitored. Communication between operators of plant parameter indications appears to have been good. All crew members were knowledgeable of plant parameters that indicated that a loss of coolant situation was in progress during this early period of the event; plant parameters did not indicate that any other event was in progress. The operators had not reached any conclusion about the location of the RCS leak at this point of the event.

The crew isolated letdown about 2 minutes after decreasing pressurizer level and pressure were identified in an attempt to isolate the leak, which some members of the crew suspected was an inter-system LOCA through the Gas Stripper. The operators also manually started the third charging pump and energized the pressurizer backup heaters. The crew continued to observe pressurizer pressure and level decrease for about 6.5 minutes after these actions were taken. Pressurizer level decreased steadily at 1.5% per minute; pressure continuously decreased, but the rate of decrease was mitigated because the pressurizer heaters were energized. Pressure was still decreasing at a rate of 15 psia per minute just before the manual trip.

During the six minute period prior to the trip, several of the operators, including the CRS and TRO, suspected that a SGTR was in progress due to the Main Steam Line radiation monitor alarm (RU-140) that came into alarm when the initial observation of decreasing pressurizer level and pressure was made. The Assistant Shift Supervisor directed the Third Reactor Operator to perform the actions of procedure 42AO-2ZZ08, "Steam Generator Tube Leak," specifically section 2, "Minimize Release to Environment," because he suspected a SGTR event. The crew placed the ADVs in off, and realigned the Main Steam Dump Valves to prevent any potential radioactive release directly to the environment from the SGs.

When operator actions to regain control of pressurizer level and pressure were not successful, the Shift Supervisor ordered a manual reactor trip. The crew then followed procedure 42EP-2E001, "Emergency Operations." The main steam line radiation monitor (RU-140) that had alarmed prior to the trip, cleared shortly after the reactor trip. At the completion of "Safety Function Flow Chart" portion of "Emergency Operations," the Assistant Shift Supervisor followed the procedure portion titled, "Diagnostic Logic Tree." During the performance of this logic tree, none of the radiation monitors used to diagnose a steam generator tube rupture were in alarm. The logic tree directed the Assistant Shift Supervisor to enter 42EP-2RO01, "Reactor Trip." The Assistant Shift Supervisor consulted the Reactor Trip procedure and could not meet the entry conditions based on low pressurizer level. The diagnostic logic tree was repeated a second time with the same results. At this point the Assistant Shift Supervisor and the Shift Supervisor decided to enter 42EP-2RO08, "Functional Recovery," (FRP). Entry into the FRP is required when event diagnosis does not identify an optimal recovery procedure. Actions were taken in the FRP which lead to restoration of pressurizer level. Specific actions to mitigate the SGTR event using FRP Attachment 3 were not taken because the process radiation monitors that would have required use of Attachment 3 were not alarming when the procedural decision was made at FRP step 3.21. Even though the operators observed two independent radiation monitor alarms within about 5 minutes of completing step 3.21 (between 0520 and 0529), indicating a SGTR had occurred, strict procedural compliance did not allow the operators to take action upon receipt of this information, even though the operators knew the alarms had actuated.

Three on call Shift Technical Advisors (STA) responded to the Unit 2 control room; the first one arrived at about 0500. The STAs performed three main functions in the control room, which were: (1) plant status and safety function monitoring; (2) EOF communications and data collection; and (3) TSC communications and data collection. Interviews conducted by the AIT with the STAs did not identify any key roles that the STAs performed during this event; it did not appear that their actions (or inactions) contributed significantly to the mitigation strategy for this event; however, it appeared that the STAs fulfilled their responsibilities during this event.

The inspectors were also concerned about the EOP Diagnostic Logic Tree (DLT) having led the operators to the incorrect diagnosis two times. The licensee's practice, and the operators' training, was that at each branch point of the tree the branching decision was based upon the plant conditions existing at the moment in time the decision was called for (the so-called snapshot approach) without accounting for trends or past plant conditions. Specifically, at the branch point leading to SGTR, the question posed inquired whether certain radiation monitor alarms were in existence at that time. Since the answer at that time was 'no,' the DLT did not branch the operators out into a SGTR event. However, if the question had been changed to inquire whether an alarm had been experienced in the past (during the event, the main steam line monitor had been in alert before the reactor trip) the DLT would have branched the operators to the SGTR event, which would have saved some amount of time in isolating the SG. The team considered that the licensee's 'snapshot' practice of using the EOPs flawed the DLT, at least in this instance, and represented a weakness.

In response, the licensee revised the approach to the particular decision point in question to consider whether certain radiation monitors were trending upward or had alarmed in the near past. In addition, the licensee agreed to review their DLT again to assess whether the 'snapshot' practice resulted in correct branching decisions at other branch points.

When pressurizer level was restored to about 33% and FRP exit conditions were satisfied, the crew implemented 42EP-2RO03, "Steam Generator Tube Rupture." This procedure directed the operators to isolate the affected steam generator, and continue with a plant cooldown and depressurization.

The inspectors questioned whether certain radiation monitors would alarm in a timely manner to allow the operators to properly diagnose SGTR events. The inspectors learned that the Alert and Alarm setpoints for the Main Steam line (RU 140) and the condenser vacuum pump exhaust monitor (RU 141) were based upon not exceeding regulatory dose requirements at the site boundary, a high value relative to the expected readings which would indicate a SGTR. The licensee calculated that the condenser exhaust monitor (RU 141) would not have alarmed for about 20 minutes following the Unit 2 event, even if it had been functional (the licensee discovered after the plant was cooled down that RU 141 was not functional due to an electronic problem). The team considered that RU 141 would not be a timely and reliable indicator of an SGTR event if set at a level meeting the dose requirements at the site boundary.

In the case of the blowdown monitor (RU 5), the event demonstrated that a transport time of about 9 minutes was required to allow contaminated fluid to reach the detector from the SG. Further, the SG blowdown isolates on a CIAS signal. Therefore, at least in this event, the team concluded that there was a high likelihood that a SGTR, of sufficient magnitude to be greater than charging pump capacity, would result in a

CIAS signal, isolating the blowdown line, before the blowdown monitor could alarm.

In the main steam line monitor case, an alarm was received (probably due to N 16) before the reactor trip, but cleared when the reactor trip caused N 16 production to cease. However, since the alarm setpoints for these monitors are based upon offsite dose at the site boundary (500 mrem/hour), and not steam generator activity or power level, these alarms may not reliably and consistently indicate a SGTR event in a timely manner for all plant conditions.

The team also concluded that the SG blowdown monitor and the condenser vacuum pump exhaust monitor alarms may not reliably and consistently indicate a SGTR event in a timely manner.

The NRC has issued several generic communications in the area of primary-to-secondary leakage monitoring including: (1) NRC Bulletin 88-02, "Rapidly Propagating Fatigue Cracks in Steam Generator Tubes," (2) NRC Information Notice 88-99, "Detection and Monitoring of Sudden and/or Rapidly Increasing Primary-to-Secondary Leakage," and (3) NRC Information Notice 91-43, "Recent Incidents Involving Rapid Increases in Primary-to-Secondary Leak Rate." The emphasis of the latter two communications was to alert pressurized water reactor licensees of the potential problems in detecting and monitoring of sudden and/or rapidly increasing leakage through the SG tubes from the primary system to the secondary system.

The guidance in the Information Notices stressed the use of appropriate radiation monitor alarm setpoints [in particular, air ejector (condenser vacuum pump exhaust) radiation monitors] for the detection and monitoring of sudden and/or rapidly increasing primary-to-secondary leakage. In addition, the Information Notices warned that liquid samples from the SG blowdown system may not show significant increases in activity for rapidly increasing primary-to-secondary leakage even though the leakage rate may be in excess of the Technical Specification limit. As a result of these Information Notices, the licensee did evaluate the appropriateness of the alarm setpoints for the SG blowdown radiation monitors; however, the setpoints for the condenser vacuum pump exhaust radiation monitor, which are set at a level consistent with off-site dose consequences as identified by the licensee's Offsite Dose Calculation Manual, were considered appropriate. The licensee considers that their response to the

Information Notices was appropriate. In light of the recent events and industry experience, additional consideration should be given to the appropriateness of the condenser vacuum pump exhaust radiation monitor alarm setpoints. The team noted that the licensee was planning a plant modification which would result in the ability to set the monitor alarm setpoint at a lower level.

The Team was concerned about the delay in isolating the faulted steam generator. The Team considered that strict procedural compliance and training accounted for a portion of the delay. The facts determined by the team, based upon operator and management interviews, are:

- Most of the operators had concluded early in the event that the event was probably a SGTR.

- The operators felt they could not enter the SGTR procedure and bypass the Functional Recovery Procedures (FRP), because they were concerned that if they were wrong they may compound dealing with a different event, and that public health and safety were being maintained by using the FRP. Although the event was initiated at 0434, the SGTR procedure was not entered until 0640 and the SG was not isolated until 0728.

- The operators were proceeding through the FRP in a deliberate manner, paying close attention to procedure compliance, as they had been trained.

- The above considerations provided one component of the overall delay in isolating the steam generator.

- Management discussed and weighed the advisability of conducting shift turnover prior to isolating the faulted SG.

- Management made the decision to conduct shift turnover prior to isolating the SG based, in part, on their determination that the plant conditions were stable and not deteriorating and their belief that a fresh crew was desirable.

- The above two considerations provided an additional delay in isolating the SG.

Based on interviews with personnel, review of procedures, and analysis of available data, the AIT identified certain strengths and weaknesses associated with the EOPs, operator training, and plant equipment, that affected operator performance during this event.

Strengths identified during this event included the following:

- When directed by the Safety Function Flow Chart to trip 2 reactor coolant pumps (RCP), the primary reactor operator tripped the reactor coolant pumps associated with the isolated spray valve, thereby ensuring an operable pressurizer spray valve.

- The prompt actions of the crew to minimize possibilities of steam release to the environment before the actual event had been procedurally diagnosed may have prevented any offsite releases through these flowpaths. These actions included placing the ADVs in off and realigning the Main Steam Dump Valves (before trip); and isolating the condenser hotwell dump to the CST.

- Upgrade of the emergency operating procedures, about a year ago, resulted in better guidance to the operators as compared to the previous revisions.

- No failures of any major engineered safety features equipment occurred.

Weaknesses identified during this event included the following:

- This event (steam generator tube rupture) was included in the simulator training program; however, the operators were led, by simulator training, to believe that the radiation monitor alarms would occur within 2 to 3 minutes of event initiation.

- The radiation monitoring system does not provide a consistently reliable and timely indication of a steam generator tube rupture.

- Procedural guidance in the EOPs did not address: (1) the methods to be used to cooldown the ruptured SG; (2) how to control VCT level after shifting charging pump suctions; (3) actions to be taken when a radiation monitor alarm occurs after the associated FRP step was performed; and (4) RCS depressurization when FRP 42EP-2R008, Appendix FQ

(Pressure and Inventory Control), is used to maintain RCS inventory.

- When classifying the event, some operators appeared to discount the initial indications of a leak rate in excess of charging capacity because they were unable to determine the leak source.

- Use of the FRP to mitigate this event, instead of the SGTR optimal recovery procedure, resulted in significantly longer times to isolate the ruptured SG and initiate RCS cooldown and depressurization. This resulted in a larger radioactivity release from the RCS into the secondary system outside of containment.

Selection of the Functional Recovery procedure by the crew delayed the isolation of the faulted steam generator, but was procedurally correct. The licensee's EOPs do not allow the operators to rediagnose an event after entering the FRPs, even though information received after FRP entry would conclusively indicate that an optimal recovery procedure should be used. However, use of the Functional Recovery procedure ensured actions necessary to protect public health and safety.

2. Equipment/System Performance

The AIT reviewed the sequence of events discussed above to verify that all systems actuated as designed. The AIT noted that all plant safety-related equipment, except for the E charging pump which tripped when shifting suction flow paths, functioned as designed in that the equipment operated when it received an actuation signal.

a. Charging Pump Performance

Early in the event the operators had started all charging pumps in an effort to regain pressurizer level. After the reactor trip, as directed by step 3.33 of the Functional Recovery procedure, the operators shifted the suction of the charging pumps from the volume control tank (VCT) to the high side suction of the refueling water tank (RWT). During the performance of this step, the E charging pump tripped. Post-event evaluation determined that the three charging pumps and a boric acid makeup pump were running when the operators switched charging pump suction to the

RWT. The operator first opened a valve to the RWT and then closed the valve from the VCT. Charging pump E tripped when the VCT valve was closed, which configured the four pumps to take suction from a long 3 inch diameter pipe. Post-event calculations showed that the charging pump suction pressure was below the trip point with the four pumps running.

The following post-event suction pressure trip settings were found:

Charging Pump	Power Train	Trip Setting, psia
1 (A)	A	12.65
2 (B)	B	11.75
3 (E)	A	12.20

Other things being equal, the trip settings imply that the A charging pump would trip first. However, there are small variations in the piping and pressure actually occurring at each pump suction and perhaps in the sensing system response times which apparently led to the E pump tripping first. The corresponding reduction in flow allowed the other pumps to remain running, consistent with the post-event calculations. The operators restored the third charging pump to operation by temporarily re-aligning the charging pumps' suctions to both safety and non-safety grade suction paths; then completing the suction transfer of all three pumps to a third safety related path.

b. Radiation Monitoring System Performance

The radiation monitoring system had been generating numerous alarms during the night shift. In the morning hours at Palo Verde, temperature inversions may cause gas problems in the auxiliary building and cause numerous area radiation monitors to alarm.

RU-15 (Waste Gas System Area Combined Ventilation Exhaust Monitor) had been in and out of alarm repeatedly during the morning of the event. This alarm signaled the possibility of problems associated with the gas stripper. In addition, RU-7, the auxiliary steam condensate receiver tank radiation monitor, alarmed prior to the event. Channel 2 of RU-140, #2 steam line radiation monitor, remained in alarm throughout the event until about 1 minute after the trip, and channel 1 also alarmed approximately 6 times prior to the trip, but quickly cleared after the manual trip. When these alarms cleared, there were no radiation monitor indications of a SGTR; this added some confusion for the operators who were trying to diagnose this event. In the interval between when the tube ruptured and when the operators tripped the plant, RU-4 and 5, steam generator blowdown radiation monitors and RU-141, condenser air removal radiation monitor did not alarm as the operators had been instructed during simulator training. Based on plant design, SG blowdown isolated on the containment isolation actuation signal (CIAS) and could not provide indication until unisolated by step 3.6 of the Functional Recovery Procedure. When blowdown was unisolated, RU-4 and 5 came into alarm 9 minutes later, at the same time RU 141 alarmed. This provided clear indication to the crew that a steam generator tube rupture had occurred.

c. Pressurizer Spray Valve

One plant component was out-of-service prior to the event. Pressurizer spray valve 100F was isolated due to excessive leakage past its seat. This did not present any problems during the mitigation of this event. When directed by the Emergency Operations Procedure to secure one RCP in each loop, the primary reactor operator chose RCP 1B and 2B. RCP 1B is the pump in the loop with 100F. This action by the reactor operator provided the plant with optimum spray flow through the inservice spray valve in the loop with the running RCP.

d. Emergency Diesel Generator (EDG) Operation

The licensee's EDGs were operated unloaded for eight hours during the event, followed by a 15 minute run at 85% load. Carbon buildup in EDGs during unloaded operation is of potential concern. For long term life/reliability, Cooper-Bessemer recommends that a gradual loading of the EDG of 1.5 hours be accomplished and that a loaded engine run should not be less than 4 hours to achieve thermal stability (from the licensee's Nuclear Administrative and Technical Manual, "Emergency Diesel Generator A," 42OP-2DG01, Rev 08.01). Licensee representatives indicated that such recommendations did not constitute an operability consideration, that tin transfer is more of a concern than carbon buildup, and that some of the Cooper-Bessemer owner's group recommendations regarding tin envelope any potential carbon concerns. (The licensee participates in the owners group.) Step 7.3.2.2 of procedure 42OP-2DG01 states that if an EDG has operated for >=6 hours since the last loaded operation, then it should be loaded to greater than or equal to 4.2 MW for at least 15 minutes. Provisions are made for not adhering to the 1.5 hour loading time when circumstances warrant. During the event, loading was accomplished in a few minutes to avoid committing operating personnel when numerous activities to deal with the event were ongoing. No deviations from operating procedures were identified.

The licensee's operating philosophy is to first mitigate the event and fully recover the plant. Next the mitigation and recovery actions are assessed for adequacy and to assure complete coverage. These steps are followed by verifying and resetting safety signals and addressing equipment that was automatically started, not previously turned off, and is no longer needed. The EDGs are typically in this equipment category because of the complexity of shutting them down prior to resetting safety signals. (EDGs are also left running in case they should be needed early in the event.) These actions can easily occur several hours after event initiation. For example, the EDGs ran unloaded for four hours following a Unit 3 reactor trip in February when the event was relatively routine. The March 14 steam generator tube rupture event involved more operator actions, used more procedures, and included a shift turnover. The licensee does not consider the eight hour EDG run time to be inappropriate when balanced with the need to perform other operations during the event.

e. <u>Pressurizer Vent System</u>

The Palo Verde units are equipped with a pressurizer vent system that meets single failure criteria. This system is required to mitigate the postulated design basis steam generator tube rupture (SGTR). In practice, the auxiliary pressurizer spray system is preferred and the vent system is used as a backup depressurization means.

The vent system was not used during the March 14 SGTR event.

f. Letdown

An indicated letdown flow rate of about 10 gpm was reported following letdown isolation. This had been observed during previous transients at Palo Verde and its cause has not been determined. Post-event examination appears to have established that the letdown flow instrumentation converter, including the square root extractor, were operating correctly. Potential causes that remain include loss of a single phase condition in the reference leg of the differential pressure transmitter, partial draining of part of the system, and operator error (the letdown flow rate and pressure indications are identical and are side-by-side in the control room, and the reported value is about the deflection caused by the expected pressure). The licensee's evaluation was continuing.

g. Other Equipment Malfunctions

The licensee reported several equipment malfunctions that are not addressed elsewhere in this inspection report. These items are as follows:

- RCS pressure indicator PT-190A on recorder RCA-PR-102A was reading 1500 psia after pressure had been reduced below this pressure.
- A Blue Safety Equipment Status System (SESS) light was received on Steam Generator #2 blowdown isolation valves SGB-UV-219/221/228. The valves had been verified closed. The SESS, a non-safety related system, was the malfunctioning component in this case.
- The Qualified Safety Parameter Display System (QSPDS), channel "A" Core Exit Thermocouples were reading approximately 25 degrees high causing subcooled margin to be question marks.
- A Blue SESS light was received on ECB-E01 when the chiller was operating, due to a malfunction in the SESS.

- The CEDM Power bus undervoltage relay #3 did not appear to respond properly. This alarm came in 49 seconds after the three other undervoltage alarms.

These malfunctions did not affect the operator's ability to deal with the event and the licensee is evaluating these items as part of its incident evaluation.

3. <u>Emergency Operating Procedure Use and Adequacy</u>

The AIT reviewed the emergency operating procedures used during this event. This review revealed several areas where the technical content of the emergency operating procedures could be improved. The procedure weaknesses are discussed below:

- The diagnostic logic tree (DLT) relies upon radiation monitor system (RMS) alarms for event diagnosis. The DLT incorrectly assumes that RMS alarms are indicative of an event. This event demonstrated that the event may occur, and the RMS alarms assumed may not be received. The radioactivity levels may be sufficiently low enough that the alarms will not be received, but trends may be established, however, the DLT does not address trends on the RMS. This observation is applicable not only to steam generator tube ruptures, but also to small break loss of coolant accidents outside of containment and also inter-system loss of coolant accidents. However, the licensee has stated that inter-system and small break loss of coolant events would still be diagnosed properly.

- Actions are taken in the Functional Recovery procedure (step 3.6) to restore steam generator blowdown. Later at step 3.21, it instructs the operator to check for indication of a steam generator tube rupture. Insufficient time may elapse between these two steps to allow for the RMS alarms to respond. This may lead to a delay in event diagnosis, and increase the time before the affected steam generator is isolated.

- The Functional Recovery procedure decision table provides the CRS with the information to choose a safety function success path for each safety function. If the success path which uses Appendix FQ (Pressure and Inventory Control) is chosen to satisfy the pressure and inventory safety function, actions in this appendix do not establish an RCS depressurization. In events when RCS pressure is stable above the HPSI shutoff head, the operator will be attempting to restore pressurizer level, but only with charging flow. Actions to establish a cooldown and depressurization are contained in section 5, "Long Term Actions." The time required to complete section 3, "Event Control," and enter section 5 may lengthen the time of the event, when in fact the depressurization may quickly assist in completing Appendix FQ.

° Guidance in the FRP to mitigate the SGTR event was not performed because the process radiation monitors that indicate a SGTR event had still not alarmed when the evaluating FRP step for a SGTR was performed. Within about the next 5 minutes, the operators had two independent radiation monitor alarm indications that would have triggered FRP mitigating actions for the SGTR. However, strict procedural compliance did not allow the operators to repeat the SGTR evaluation step in the FRP because it was not a continuously applicable condition.

° The licensee's EOPs do not allow for re-diagnosis of an event after entering the FRP, even though information received after FRP entry would conclusively indicate that an optimal recovery procedure should be used. This delays event mitigation because the operators must complete the FRP, which is a lengthy procedure, before proceeding with optimal recovery actions.

° Review of the licensee's EOP development process revealed a key contributor to the implementation of an inadequate diagnostic procedure. Guidance provided by the Owner's Group Emergency Procedure Guidelines (EPG) identified that "activity in the steam plant" should be used to diagnose SGTR events. The licensee implemented this guidance by evaluating radiation monitor <u>alarms</u> in the steam plant, without adequate consideration of the alarm setpoint basis or trends below the alarm setpoint. The licensee further documented that this implementation did not deviate from the EPGs; independent review of the licensee's EOP to EPG deviation document by the reactor vendor also failed to identify this area as a deviation from the EPGs.

In addition to the above, the AIT noted that operator action was required to prevent an overfilling of the VCT during the performance of 42EP-2EO03, "Steam Generator Tube Rupture." All charging pump suction was aligned to the RWT, but the RCP seal bleedoff flow was still directed to the VCT. The slow filling of the VCT diverted operator attention for a short period until a suitable method of maintaining VCT level was established.

D. Licensee Emergency Plan Implementing Actions

1. Classification

On March 14, 1993, at 0435 MST, the operators noted that pressurizer level was decreasing. At 0437 the operators isolated letdown flow and started the third available charging pump. Pressurizer level continued to decrease until level reached about 25%. The operators tripped the reactor at this level (0447) due to loss of coolant inventory and resulting loss of pressurizer heaters. The plant operators recognized that cold leg temperature and turbine load had remained constant as pressurizer level was decreasing. The Assistant Shift Supervisor stated that they recognized that a RCS leak in excess of charging pump capacity was in progress prior to the trip, and that he had discussed this concern with the Shift Supervisor (SS).

Prior to the reactor trip, EPIP-02, Emergency Classification, would require the event to be classified by Appendix B, Tab 2. Prior to the trip, and for a period of time after the trip due to HPSI injection, RCS leakage exceeded available charging pump capacity. Nevertheless, the leakage rate in excess of charging pump capacity was not recognized by the SS when he classified this event. The event was classified as an Alert at 0502. EPIP-02, Tab 2, requires that RCS leakage in excess of available charging pump capacity be classified as a Site Area Emergency. The event was, therefore, not properly classified, as required by the licensee's procedures.

The licensee's investigation considered that the event was properly classified. The licensee concluded that the SS did not reach the conclusion that, prior to the reactor trip, RCS leakage exceeded charging pump capacity. Subsequent to the trip, 3 charging pumps maintained pressurizer level with no indicated HPSI flow. However, the Team concluded, after review of control room indications and operator interviews, that information indicating RCS leakage greater than charging pump capacity was clearly indicated in the control room prior to the reactor trip.

EPIP-02, Appendix A, is the designated event classification method to be used subsequent to a reactor trip. This method is a "barrier criteria" classification method and specifies a set of different conditions. The procedure states that a check be made by "...all of the following conditions that are in progress or have occurred." One check results in an Alert classification, two checks result in a Site Area Emergency, and three or more would result in a General Emergency. After the trip, RCS leakage exceeded 44 gpm, which was the condition that required the procedure check which was used by the facility to classify an Alert. However, prior to the trip, RCS leakage had exceeded available charging pump capacity. This was a condition which had occurred and would have been checked resulting in a Site Area Emergency had the licensee followed their procedure.

Although neither the licensee nor the AIT were able to confirm it, several of the operators in the control room believed that, at about 0700, a Unit 2 Auxiliary Steam relief valve lifted resulting in a release of steam to the atmosphere. The operators isolated the valve at about 0720, and at about 0804 the unit started receiving Auxiliary Steam from the common header which was being supplied by Unit 3. The TSC logged a telephone call, without identifying the caller, reporting that the Unit 2 Auxiliary Steam Relief valve had opened. The Emergency Coordinator in the TSC stated that he thought they were releasing clean steam from the common header when the relief valve opened. This was reported to the NRC by the Emergency Director in the EOF as a release of Unit 3 steam, when the control room staff had knowledge that Unit 2 steam was supplying Unit 2 auxiliary steam. Personnel in Unit 2 stated that they knew that it was a release of Unit 2 steam. At this time the unit was in an Alert due to having a procedural check for the condition of RCS leakage greater than 44 gpm (this leakage had been identified by the licensee as primary to secondary leakage). EPIP-02, Appendix A, would have received an additional check for the condition that primary to secondary leakage in excess of 10 gpm concurrent with a steam release in progress. These two conditions would have procedurally required the licensee to declare a Site Area Emergency. Therefore, considering the above information, the team, again, concluded that the event was not classified as required by the licensee's procedures.

The licensee, however, had an opportunity to assure that Unit 2 Auxiliary Steam (AS) would not be supplied from a contaminated source in the event of a worsening of the known tube leak in SG-2. On March 4, 1993, the offgoing Unit 1 night shift identified that "U-2 has a small S/G tube leak, may want to change unit supplying AS header." At 1515, the Unit 1 day shift documented in the Unit log the AS system status as "AS Unit 3 is now carrying the cross-tie header due to Unit 2 having a very small steam generator tube leak." However, the Unit 2 Auxiliary Steam header continued to be supplied by Unit 2 steam. Although management reviews the logs, the opportunity to assure that the Unit 2 AS system was supplied by an alternate source was missed.

The licensee did not determine that a steam generator tube rupture had occurred until 0640. This delay of 2 hours and 5 minutes was due, in part, to EOP and radiation monitor concerns discussed previously in this report. The licensee Emergency Plan Implementing Procedures do not differentiate between a steam generator tube rupture and a small break loss of coolant accident (SBLOCA). NUREG-0654 would require that a SBLOCA in excess of makeup capacity be classified as a SAE. At operating pressures prior to the reactor trip, the RCS leakage exceeded the makeup capacity. Discussions with the facility system engineer for the HPSI system indicated that the HPSI system flow indication would probably not indicate flows of less than 65 gpm per injection line due to the square root converter low flow cutoff. The system engineer felt that the HPSI system was injecting some flow, in addition to the maximum charging flow, during the initial post-trip timeframe. Their conclusion was based on system pressure, discharge pressure of the HPSI pumps, and the suction head provided to the pumps. NRC guidance in NUREG-0654 would require that a steam generator tube rupture of this size be classified as an Alert if it is treated separately from a SBLOCA in excess of makeup capacity. The licensee's procedures classify a SGTR event at a more serious classification level than the NRC guidance would require. This is considered a weakness in the licensee's classification process.

EPIP-02 Section 4.3 states:

"<u>NOTE</u>

> Events shall be classified as soon as possible in order to allow for prompt notification of Offsite

Authorities. Prompt notification means within 15 minutes from the time at which Operators recognized that events have occurred which make declaration of an Emergency classification appropriate."

It took 15 minutes from the time of the reactor trip until the event was declared to be an Alert. The classification thus occurred within the specified time frame.

2. Notification

The inspector reviewed the event notification forms which had been completed by the licensee. The Alert was declared at 0502 and the notification to the offsite agencies commenced at 0514.

10 CFR 50.72.a.4 and EPIP-11, Step 3.2, require that the Emergency Response Data System (ERDS) be activated within one hour after an Alert or higher event is declared. An Alert was declared at 0502. ERDS was activated at 0612. Therefore, ERDS was activated one hour and ten minutes after an Alert was declared.

3. Staffing

The Emergency Plan, Table 4.2-4, defines minimum staffing requirements for PVNGS for nuclear power plant emergencies. The table lists a staffing augmentation goal of 60 minutes for TSC support staff. EPIP-11, Technical Support Center/Satellite TSC Activation, Step 3.1, states: "The STSC and TSC should be activated within the augmentation goals set forth in the PVNGS Emergency Plan i.e., within 30 minutes for the STSC and 60 minutes for the TSC." The TSC was activated at 0645, or 1 hour and 43 minutes after the Alert declaration which required the staff augmentation.

The table referenced above also lists a staffing augmentation goal of 60 minutes for EOF support staff. EPIP-13, Emergency Operations Facility Activation, Step 3.1, states: "The EOF should be activated within the time augmentation goals set forth in the PVNGS Emergency Plan, i.e., 60 minutes." The EOF was activated at 0642 or 1 hour and 40 minutes after the Alert declaration which required the staff augmentation.

When the emergency response facilities (ERFs) were finally activated, a large staff of highly qualified personnel staffed the facilities.

The licensee's investigation concluded that the augmentation times listed in the EPIP's are a "GOAL." They also concluded that no adverse effects resulted from exceeding the 60 minute goal. They concluded that there is no clear requirement to meet the 60 minute goal.

As discussed in Section IX of this report, the onsite security force did not appear to have adequate personnel to fully implement EPIP-20.

4. Information Updates

After the ERFs were activated, information updates appeared to be done in a timely manner and to be adequate in content. One example of licensee miscommunication occurred when a report of a steam release from Unit 2 was identified to the TSC and EOF. Unit personnel knew that the steam was Unit 2 steam. The EC in the TSC and EOD in the EOF were told that it was steam being supplied from the plant header which was Unit 3 steam.

5. Emergency Response Coordination

Licensee staff indicated that a number of persons called the Units 1 and 3 Control Rooms to question their assembly instructions. They were not in the affected unit and were unsure that the assembly instructions were applicable to them. Many of these personnel did not report to their assembly areas in a timely manner.

Licensee personnel reported that they received several telephone calls from plant personnel, who were off duty at home, trying to get personal information. This was a distracting influence on the operators.

6. Licensee Investigation Actions

A licensee post-alert critique was not conducted. The licensee decided to conduct a full incident investigation using an Incident Investigation Team (IIT) investigation. This investigation was not complete at the time of this inspection.

7. Conclusions

Based upon the emergency response evaluations, the AIT had the following conclusions:

- The licensee's classification procedures do not implement the NRC guidance which would allow an SGTR event to be classified as an Alert. Instead, the licensee's procedures may classify a SGTR event at a higher level (Site Area Emergency) under conditions where leakage exceeds the charging pump makeup capacity.
- The licensee failed to recognize in the EPIP checklist that the total leakage during the event exceeded the available charging pump makeup capacity prior to the reactor trip and, therefore, failed to classify the event in accordance with their EPIPs.
- The licensee failed to meet their one hour goal of activating the TSC and EOF.
- The licensee failed to activate the Emergency Response Data System (ERDS) within one hour as required by 10 CFR 50.72.
- The licensee missed an opportunity to reduce the potential for a contaminated steam release by shifting the Unit 2 auxiliary steam system from the Unit 2 source to the Unit 3 supplied header on March 4, 1993.
- When the TSC and EOF were activated, the staff was comprised of senior personnel who were highly qualified.

E. HUMAN PERFORMANCE EVALUATION

The AIT evaluated the human factors aspects associated with the event, including: teamwork; command and control; communications; staffing; training; and other human performance issues.

1. Training

a. Operator

Operator training was reviewed to determine any potential impact the training program may have had on the operators' ability to mitigate the event.

The team reviewed training objectives, lesson plans, and classroom and simulator course materials related to steam generator tube rupture, implementation of 10 CFR 50.54x, determination of an unmonitored release, Radiation Monitoring System operation, control room staff crew responsibilities, and crew coordination and communications.

Licensed operator continuing training course overviews and lesson plan objectives for classroom and simulator training were reviewed for seven training cycles from September 1991 through January 1993. Emergency Operating Procedures, including steam generator tube rupture and functional recovery operations, were covered in classroom lectures. Various steam generator tube rupture scenarios were exercised in the simulator. Lesson plans and training materials appeared to adequately cover these areas with a notable exception discussed below.

Licensed operator training to detect unmonitored release paths and determine Emergency Plan Implementing Procedures (EPIP) emergency classification is discussed in Emergency Plan Implementation (NLE01-0-RC-001-001), and Administrative Training, Effluent Release (NLN01-01-RC-015-001). These documents do not appear to describe potential pathways within plant systems where unmonitored releases may occur. In addition, licensed operator simulator training is used to reinforce the concepts of detecting and recognizing unmonitored release pathways. Typically the scenarios involve transients in which high pressure, high flow pathways such as steam generator safety valves, atmospheric dump valves, or main steam bypass valves (numbers 7 and 8) are recognized as potential unmonitored release pathways. Small steam release pathways such as a 50 psi auxiliary steam line, which does not have direct control room indication, are not specifically focussed on during simulator exercises or reviewed in detail during classroom training. This issue was further discussed with several Palo Verde training and operations personnel and, as a result, appears to represent a training weakness.

b. Simulator Fidelity

The team performed a static walkdown of the simulator control boards, observed a dynamic simulation of a steam generator tube rupture, and discussed the modelling capabilities of the simulator with Palo Verde simulator training personnel.

The Palo Verde simulator is a model of the Unit 1 control room. Significant differences between the simulator and the Unit 2 control room are minimal, and are tracked in the licensees Simulator Configuration Management Program, controlled by the Nuclear Training Simulator Support Group. Simulator modeling differences are evaluated for potential impact on operations. Operators are briefed by the training staff on significant changes to the simulator which have resulted from modifications to the units.

The Palo Verde simulator can model a variety of tube ruptures. Typical tube rupture scenarios will model SGTR Optimal Procedure entry conditions such as radiation monitor alarms on RU-141, RU-140, RU-139, RU-5, and RU-4; steam flow - feed flow mismatches; and steam generator level changes. Alarm setpoint values for the RMS alarms are based on data that was generated from Unit 1 in March of 1991. These RMS setpoint values are not changed in the simulator to approximate those in the individual units. Operators are trained to expect radiation monitor alarms in order to diagnose a tube rupture event. Additional indications are used to confirm the diagnosis once in the optimal recovery procedure. The tube rupture scenarios currently exercised in the simulator provide RMS alarms on at least one of those monitors required to diagnose the event. Since the Unit 2 SGTR deviated from training, the inspector considers that this represents a negative training situation.

The simulator HPSI flow indications do not indicate flow above an RCS pressure of approximately 1800 psia, the design shutoff head of the pump. Simulator training does not currently discuss the possibility that HPSI flow at RCS pressures approaching 1860 psia may occur. Training personnel indicated that, based on current simulator training, operators would not be expected to know that under the conditions associated with the Unit 2 event, HPSI flow into the RCS may have occurred. This, too, represents a negative training situation.

Potential weaknesses in the simulator modelling include the RMS alarm setpoints and RCS activity which may not be indicative of actual plant conditions, and the HPSI flow indication. As a result, operator expectations for indications associated with tube rupture events may be somewhat misleading.

The training personnel contacted said they were planning to model the unit 2 event when the TDAS data was available and training schedules permitted. The training personnel appeared responsive to following up the results of the licensee's investigation and to incorporate lessons learned from the Unit 2 event into the licensed operator continuing training program.

2. <u>Human System Interface</u>

Controls and displays for carrying out the implementation of EOP Safety Function flowcharts, the Diagnostic Logic Tree, and verifying SGTR optimal recover entry conditions were reviewed during a panel walkdown in the Simulator. All indications and controls needed to accomplish the actions required were available and suitably labeled. Post accident monitoring instrumentation, and additional qualified instrumentation including Q-SPDS were well demarcated, provided adequate parameter indication, and, with the exception of the HPSI flow indication low flow cutout and man-machine interface weaknesses of the RMS system described below, instrumentation and controls provided operators with adequate indication and control to mitigate the event.

HPSI flow indications are indicated as 'zero' below approximately 65 gpm per loop due to a low flow cutout in a square root converter in the HPSI flow instrumentation. HPSI system engineers indicated that flow rates on the order of 20 to 30 gpm per loop would be expected at the post-trip RCS pressure (1860 psia) experienced during the event. As a result, operators may not have had a positive indication of actual HPSI flow rate into the RCS. This lack of indication may have influenced the operators determination that RCS leakage was not in excess of charging capacity, and the subsequent errant emergency classification.

The current RMS indications are incorporated into an operator accessed CRT-based interface display system. The system enables the operators to select from a variety of displays including, but not limited to: (1) a status grid display providing a one page summary of all monitor channels; (2) an alarm display providing a multi-page list of monitors having outstanding alarm conditions or which are off-line; (3) a database display providing a single page summary of specified channel information (setpoints, status, conversion factors, etc.); (4) a radiation trend display providing a graphic representation of the last 24 radiation levels for a particular monitor in selectable time intervals of either 10 minutes, 1 hour, or 1 day spans; and (5) a radiation level histogram display providing a single page tabulated list of monitors.

As a result of the event evaluation, the team identified several weaknesses with the current RMS system which may contribute to the operator's difficulties with radiation monitoring tasks. These weaknesses included: (1) radiation monitor identification access numbers which are different than the common RU identification numbers and require the operators to either memorize or use a cross-reference table adjacent to the monitor to access monitor information; (2) trending capabilities which only permit a single radiation monitor to be displayed on the screen at any one time; and (3) histogram displays which can display several radiation monitors simultaneously, but require the operators to recall from memory or transcribe individual radiation values in order to determine how these monitors are trending. Accessing additional monitor information will overwrite the current display and, therefore, limit data available to operators at a given time. Although these interface weaknesses did not appear to contribute directly to the mitigation of the event, they do potentially contribute to operator difficulties with using the RMS system.

3. Command, Control, and Communications

Expectations and administrative controls on crew communications are embodied in the procedures for Conduct of Shift Operations (40AC-9OP02) and Emergency Operations Procedures Technical Guidelines (40DP-9AP05). Expectations are further described in a number of training modules including Control Room Staff Responsibilities (NKS31-01-RC-065-000) and Conduct of Shift Operations (NKS31-00-RC-060-002). Training on crew communications is reinforced through role playing, simulator exercises, and specialized crew communication training.

As a result of interviews with operators involved in the event and with NRC resident personnel present in the control room during the mitigation, it appears that crew communications between the control room staff were adequate.

4. Staffing

a. Crew Composition

Requirements and administrative controls on Palo Verde operating crew staffing levels are described in Section 6.2.2, Unit Staff, of the Technical Specifications. Minimum shift crew composition during modes 1 through 4 require 1 shift supervisor, 1 senior reactor operator, 2 reactor operators, 2 nuclear operators, and a shift technical advisor.

Additional administrative controls on shift staffing are described in the procedures for Conduct Of Shift Operations (40AC-9OP02) and Emergency Operations Procedures Technical Guidelines (40DP-9AP05). The minimum staffing requirements described in these documents is similar to the Technical Specifications, with the notable exception of requiring 4 nuclear operators on shift where TS requires 2 nuclear operators on shift.

Normal crew composition during power operations typically consisting of a shift supervisor, a control room supervisor, 3 reactor operators (primary operator, secondary operator, and tertiary operator), and a shift technical advisor. Additionally 6 to 8 nuclear operators are normally assigned to a shift. These staffing levels are greater than the Technical Specification requirements and somewhat greater than the Administrative Controls. The AIT observed that the requalification examinations of the crews are conducted using the larger control room staffing levels. The AIT further observed that the crew staffing during the event contributed to its mitigation.

Although the licensee does have administrative controls in place to maintain staffing levels, it appears that if the Technical Specification minimum staffing level was in use at the time of an event requiring entry into the EOPs, staffing levels would not meet the minimum requirements for EOP implementation as defined in 40DP-9AP05, and the licensee may not be able to carry out all the nuclear operator required functions. This represents a conservative procedural inconsistency with Technical Specifications.

b. <u>Shift Scheduling</u>

The Palo Verde shift schedule consists of a six crew rotation on a six week cycle consisting of a combination of day and night shifts, a five day training period, and relief time. Shift lengths are twelve hours, typically from 6:30 through 6:30 with an approximate 30 minute shift turnover.

At the time of the event, the crew was on their third and final day of a night shift rotation. The shift supervisor, primary reactor operator, and secondary reactor operator had been on night shift the previous two nights. The control room supervisor was on his first night of rotation, the tertiary operator was on his first night of rotation, and the shift technical advisor was on twenty four hour call to the control room and arrived at the control room approximately 10 minutes after being summoned.

The event occurred 9.5 hours into the shift at approximately 0435. Discussions with the crew members indicate that fatigue was not a factor in event mitigation. The team did not identify overtime as detracting from the event mitigation. Additionally, the crew did not consider that there was an exceptionally high stress level and did not believe stress played a significant role in the event. Operators noted that because the event happened during deep backshift, the number of persons who entered the control room during the event was minimal and helped preserve the low stress levels.

5. <u>Conclusions</u>

Based upon the human factors evaluations, the AIT had the following conclusions.

The following negative training situations were identified:

- Operators are trained to expect certain radiation monitor alarms, as a positive indicator of a SGTR event, in order to diagnose the event. The Unit 2 event demonstrated that the expected alarms may not be present when the particular EOP diagnosis step is reached.

- Operators are trained on the simulator that HPSI flow will not occur above an RCS pressure of about 1800 psia. In actual plant operation, HPSI flow occurs at pressures approaching 1860 psia.

Additional weaknesses include:

- Operator training in both the classroom and the simulator do not discuss all potential pathways where unmonitored releases may occur. For example, the release pathway of the Auxiliary Steam System Relief valve was not discussed as a significant pathway.

- The HPSI low flow cutout, causing flows below about 65 gpm to be indicated as 0 gpm, may confuse operators when they need to establish whether HPSI flow occurs.

- The plant radiation monitoring system is not user friendly with respect to operator accessing of particular channels for monitoring or trending channel indications.

- The licensee's administrative controls should reflect the shift staffing requirements used in practice to respond to an event.

F. Radiological Consequences

The inspectors reviewed emergency procedures and logbooks, and interviewed licensee personnel involved in the event. The Radiological Assessment Coordinator (RAC), assigned to the Emergency Operation Facility (EOF), and the Radiological Protection Coordinator (RPC), assigned to the Technical Support Center (TSC), during the event, discussed radiation protection aspects of the event with the inspector.

Based on this review, the inspector noted the following items:

- The EOF and the TSC coordinated the movement of workers on and off site. The TSC controlled personnel movement from the non-affected units inside the protected area (PA), while the EOF controlled persons outside the PA.

- The RAC diverted vehicle traffic entering and leaving the site through the Water Reclamation Facility entrance at the northeast corner of the owner controlled boundary. The traffic rerouting was based on meteorological data and radioactive release projections.

- Vehicles and occupants were monitored for radiological contamination until the afternoon when enough data was gathered to assure that a contamination problem did not exist.

- The licensee deployed three field assessment teams that took air samples and direct radiation readings during the event. The teams did not find any abnormal radiation readings.

- Meteorological data was readily available. The licensee made dose projections at approximately 15 minute intervals. Gaseous release permits were issued for known releases. The licensee also initiated a release permit in response to reports that a relief valve had lifted on the auxiliary steam system.

- Security guards were initially assigned to secure access to the turbine building and the auxiliary building until RP could assess the impact of the SG tube leak on these normally clean areas.

- The EOF coordinated with chemistry personnel to assess the radioactive release in progress.

- Since the event occurred prior to shift turnover, the licensee held over the night shift RP technicians to ensure that adequate RP coverage was available. An additional 10 RP technicians were also called in.

The inspector toured the Unit 2 turbine building during the morning of March 15, 1993, and verified that radiation postings were in accordance with station procedures and 10 CFR Part 20 requirements. Based on results of the portions of the RP emergency response actions reviewed, the inspector did not identify any significant weaknesses.

Based upon the examinations conducted by the AIT, the Team concluded that no detectable radioactivity was released offsite and that public health and safety was maintained.

G. Radiation Monitoring System

The licensee's Radiation Monitoring System (RMS) was reviewed with respect to its performance prior to and during the event. The radiation monitors that played key roles during the event were the following:

RU-4	Steam Generator 1 Blowdown
RU-5	Steam Generator 2 Blowdown
RU-15	Waste Gas Area Combined Ventilation Exhaust
RU-140	Main Steam Line, SG 2
RU-141	Condenser Vacuum Pump Exhaust (Low Range)

RU-4 and RU-5 Did Not Respond to Leak

Based on computer data printouts, the condenser vacuum pump exhaust radiation monitor detected a radioactive release starting at approximately 0436. Computer printouts also indicated that prior to the unit trip, the steam generator blowdown monitors RU-4 and RU-5 did not detect that a SG tube rupture had occurred. The inspector verified that the monitors were operable at the time of the event, and that alarm setpoints were correct and set in accordance with approved procedures. The licensee speculated that the reason for the lack of response by RU-4 and RU-5 may be due to the location of the leak within the steam generator. However, this theory cannot be confirmed until the steam generator is drained and inspected during the refuelling outage.

RU-15 Undocumented Alarm Setpoint Change

Prior to the event, on March 14, 1993, the Unit 2 control room received several radiation alarms from the RU-15 radiation monitor (Waste Gas Area Combined Ventilation Exhaust) due to reactor coolant system (RCS) gas stripper operation. The alert alarm setpoint was set at 1.4 E-6 uCI/cc during this time. The RMS technician decided to raise the alarm setpoint on RU-15 because the alarms were becoming a nuisance to control room operators.

Section 5 of procedure 74RM-9E42, "Radiation Alarm Setpoint Determination," contains instructions for setting and controlling Radiation Monitoring System (RMS) setpoint changes for non-effluent radiation monitors. The procedure states the following:

> 6.5.6 For all noble gas monitors except RU-29 and RU-30, Radiation Protection shall be consulted to evaluate the impact of the setpoint change...

6.5.7 The basis for the setpoint shall be documented and the setpoint change processed in accordance with Section 9.0. For all noble gas monitors except RU-29 and 30, the basis for the setpoint change shall require review and concurrence from the Unit Radiation Protection Manager or designee prior to implementation.

Section 6.5 of the procedure states that the High Alarm setpoint will initially be set in accordance with the PVNGS FSAR, and subsequent alarm setpoints, based on operational experience, would be established by the Unit Chemistry Manager or his designee. The procedure further stated that these setpoints shall be controlled using Appendix J and the bases for the setpoints documented using Appendix K.

On March 14, 1993, at 0313 and again at 0348, a Unit 2 RMS technician changed the Alert and High Alarm setpoints on RU-15, and did not consult RP to evaluate the change. Furthermore, the technician did not document the change in Appendix J and did not document the bases for the changes in Appendix K. The technician also failed to obtain the Unit 2 RPM's review and approval of the revised setpoints prior to implementing the change. The alert setpoint was raised to 1.8 E-6 uCi/cc at 0313 and then raised to 2.8 E-6 uCi/cc at 0348. The high alarm setpoint was raised to 4.0 E-6 uCi/cc at 0348. This finding had no effect on the event or the licensee's actions to deal with the event.

RU-141 Out of Calibration

During the SG tube rupture event, at 1116 (MST) on March 14, 1993, the licensee took a grab sample from the Unit 2 condenser vacuum exhaust to prepare a radioactive gaseous release permit in accordance with 74RM-9EF20, "Gaseous Radioactive Release Permits and Offsite Dose Assessment." The results of the analysis indicated that RU-141 was out of calibration.

The inspector performed a records review and noted that on March 4, 5, and 9, 1993, the licensee took condenser vacuum pump exhaust gas grab samples to meet procedural and Technical Specification requirements. Gamma isotopic analyses showed that the condenser vacuum exhaust monitor RU-141 readings were biased low by factors of 5 to 8, however, the licensee did not recognize the deficiency.

Step 6.5 in procedure 74RM-9EF20 required the licensee to review the gamma isotopic results for reasonableness and accuracy, and to resolve any discrepancies by either reanalyzing the counting data, recounting the sample, re-sampling, or taking any other appropriate actions. The licensee's failure to adequately review the results of the analyses resulted in RU-141 remaining inoperable since March 4, 1993, until the licensee took corrective actions on March 18, 1993. The immediate corrective action taken was to lower the alarm setpoints on RU-141. Other corrective actions included troubleshooting the failed monitor and initiating Condition/Report Disposition Request (CRDR) Number 9-3-0216 to investigate the problem. The licensee later reported that the failure of RU-141 was due to an equipment failure in the circuitry.

PVNGS Offsite Dose Calculation Manual Section 2.0, "Gaseous Effluent Monitor Setpoints," describes the actions taken by the licensee to assure compliance with 10 CFR Part 20 limits with respect to gaseous effluent releases.

Section 2.1, "Requirements: Gaseous Monitors," requires that alarm setpoints be determined and adjusted in accordance with the methodology and parameters in Section 2.1.2.

Section 2.1 states the following:

"Action:

a. With the low range gaseous effluent monitoring instrumentation channel alarm/trip setpoint less conservative than required by the above Requirement, immediately suspend the release of radioactive gaseous effluents monitored by the affected channel, or declare the channel inoperable, or change the setpoint so it is acceptability conservative."

During the SG tube rupture event, radioactive gas samples analyzed on March 14, 1993, indicated that the Unit 2 condenser vacuum pump exhaust monitor (RU-141) high alarm setpoint was set less conservative than required, and the licensee did not suspend the release in progress, or declare the channel inoperable, or change the setpoint. Corrective actions were not taken until March 18, 1993. The improper setting of RU-141 unnecessarily confused the operators in diagnosing the event.

RU-140 Alarm Response by RMS Technician

On March 14, 1993, at approximately 0443 (MST) the Unit 2 control room received a main steam line high radiation alarm on the RU-140 radiation monitor. In accordance with alarm response procedure 74RM-9EF41, Revision 0, "Radiation Monitoring System Alarm Response," control room personnel acknowledged the alarm and notified the RMS technician. Procedure 74RM-9EF41 required the RMS technician to verify the monitor's database for proper setpoints and conversion factors, and then notify Radiation Protection and the Shift Supervisor. The RMS technician became distracted by other duties and did not accomplish the alarm response procedure requirements.

Specifically, the RMS technician stated to the inspector that, contrary to procedural requirements, he did not verify the monitor's database for proper setpoints and conversion factors, and did not notify the Shift Supervisor. The RMS technician also stated that he never "got into" the alarm response procedure after the control room notified him of the RU-140 alarm.

Conclusions

The AIT identified weaknesses in the licensee's conformance with procedures for changing monitor setpoints, resolving discrepancies between monitor readings and grab sample analysis results, and responding to radiation monitoring system channel alarms.

H. Security Consequences

The AIT evaluated the acceptability of the licensee's actions in response to their initiation of personnel assembly and accountability procedures.

Emergency Plan Implementing Procedure, EPIP-20, Personnel Assembly and Accountability, in step 3.3.10 defines accountability as:

"3.3.10 Accountability - Process to ensure that all personnel in the Protected Area have responded as Emergency Response Personnel, and that unauthorized or injured personnel do not exist within the Protected Area."

During the event on March 14, 1993 the Emergency Coordinator (EC) called for assembly at 0520. Due to questions being received from craft personnel in the non-affected units who were not responding and were requesting additional information, the EC called for assembly again at about 0545.

At 0551 the EC requested an accountability report. The report was provided to the EC at about 0605. The report provided to the EC consisted of a list of plant sectors with a list of access card (ACAD) numbers of the persons that were in each sector. Sector 2, is the area between the Protected Area (PA) entrance and the next door which would require a carded entry. According to the report, at time 0601, there were 114 persons in sector 2, as listed by ACAD number.

EPIP-20, paragraph 4.1.5, states:

"4.1.5 All personnel shall adhere to signals and messages announced, and move as quickly and safely as possible to their assembly area."

Step 4.3.7 of EPIP-20 states:

"Non-Emergency Response Personnel who are working in the protected area shall assemble in the admin. complex cafeteria (Kilowatt Cafe)."

At time 0601 it appeared that a significant number of nonessential personnel had not gone to the assembly areas which are outside of the PA.

Steps 4.3.13.1.2 and 4.3.13.1.3 direct the Security Director to:

"4.3.13.1.2 Compare the ACADs/names of personnel from OSC/STSC/TSC/Security Posts against the RPS report. Any persons on the RPS report which are not on the OSC/TSC/STSC/Security Posts accountability forms shall be considered unaccounted for unless they have previously called to the Shift Security Captain.

<u>NOTE</u>

If the card reader identification system is activated, use this system to account for personnel.

4.3.13.1.3 Provide a list by name, of all unaccounted personnel in the protected area to the Emergency Coordinator within 30 minutes of the declaration of accountability."

No list of unaccounted for personnel, by name, was provided to the EC. A list of ACAD numbers was provided to the SS at 0605. This list showed facility areas defined by sector number (not named) with the open ACAD numbers which were in that area. A review of one area by the team showed that of the 114 ACADs listed as open in the area, many were test ACADs and persons who were not onsite, and had in some cases been open for several weeks. The importance of identifying persons who are unaccounted for in a plant emergency lies in the necessity to locate injured or endangered plant personnel and also in not unnecessarily endangering search and rescue personnel.

EPIP-20, step 4.3.13.1.9 directs the Security Director:

"4.3.13.1.9 Direct the Security Force to routinely check trailers and buildings in the Owner Controlled Area (OCA) outside the Protected Area to ensure all Non-essential Personnel have reported to Assembly Area. Coordinate patrols with Radiation Protection.

No checks of the OCA were conducted at the time of accountability. According to licensee staff this was due to a decision to allocate security force members to direct traffic. Not enough staff was readily available to check the outer areas.

EPIP-20, Personnel Assembly and Accountability, Objectives, and E-Plan Section 6.6.1.2, require accomplishment of site assembly and accountability within 30 minutes of the action being required by the Emergency Coordinator. For the event, Assembly and Accountability took 6 hours and 44 minutes instead of the required 30 minutes.

Conclusions

The Team concluded the following:

- Several personnel in Units 1 and 3 did not respond to the call for assembly as required by procedure.

- The accountability report provided to the Emergency Coordinator did not list personnel by name as required by procedure. In addition, the accountability report listed, as being on site, several persons who were not on site and several test ACAD numbers.

- Security personnel did not check the OCA at the time of accountability as required by procedure, due to an insufficient security staff onsite at the time of the event.

- As a result of the above weaknesses, the licensee failed to accomplish site assembly and accountability within the 30 minutes required by procedure.

I. Assessment of Steam Generator History

1. Steam Generator Design

Palo Verde Nuclear Generating Station (PVNGS) Unit 2 has Combustion Engineering (CE) System 80 steam generators (SGs). The CE System 80 SGs are recirculating U-tube SGs which contain 11,012 high temperature mill-annealed Alloy 600 tubes with an outside diameter of 0.750" and a tube wall thickness of 0.042". Both the hot and cold leg side of the SG are equipped with flow distribution baffles which are located immediately above the tubesheet. The tube support plates (TSPs) at PVNGS are constructed of ferritic stainless steel. The flow distribution plate is a drilled hole TSP with two distinct diametral clearances depending on the location within the SG. The remaining TSPs are of the eggcrate design. The SGs have axial economizers (i.e., preheater) on the cold leg side to enhance thermal efficiency. The recirculating water from the downcomer either enters the evaporator from above the economizer on the cold leg side or from the hot leg side. A divider plate separates the economizer from the hot leg side. PVNGS went into commercial operation in 1986. A summary of the tube plugging history is given below.

2. Steam Generator Inspection Results

a. Unit 2 Preservice

Prior to commercial operation a total of 47 tubes were plugged in the Unit 2 SGs, 15 tubes in SG 1 and 32 tubes in SG 2.

b. Unit 2 Surveillance Testing Outage

During the first cycle of operation for Unit 1, a SG tube leak attributable to cold leg corner wear (described below) was identified. Since Unit 2 was performing surveillance testing at the time of the Unit 1 leak, an inspection of this area of the SG was performed in Unit 2. As a result of this inspection 30 tubes were plugged in SG 1 and 21 tubes were plugged in SG 2. The cumulative tube plugging following this outage was: 45 tubes on SG 1 and 53 tubes in SG 2.

c. Unit 2 RFO 1

During the first Unit 2 refueling outage (RFO), which began in February 1988, a total of 4707 tubes were inspected in SG 2 and a total of 10931 tubes were inspected in SG 1. The SG inspection began on 4/1/88 and concluded on 5/6/88. The degradation mechanisms observed during this first outage included:

Cold leg corner wear
Central cavity batwing wear
Outer periphery batwing wear
Vertical support and upper eggcrate wear
Potential loose part (PLP) wear

The tubes were primarily inspected with a 0.610" bobbin coil, with the smaller radius tubes being inspected with a smaller diameter probe (typically a 0.590" probe).

As a result of this inspection, five defective tubes were identified in SG 1 and six defective tubes were identified in SG 2; however, a total of 34 tubes were plugged in SG 1 and 27 tubes were plugged in SG 2. The additional tubes were plugged as a preventive measure. SG 1 had 79 tubes plugged and SG 2 had 80 tubes plugged following this outage.

d. Unit 2 RFO 2

During the second Unit 2 RFO, which began in February 1990, a total of 5534 tubes (50%) were inspected in SG 1 and a total of 10932 tubes (100%) were inspected in SG 2. The SG inspection began on 4/2/90 and concluded on 4/17/90. The degradation mechanisms observed during the second RFO included:

Cold leg corner wear
Eggcrate wear - majority at the 7th, 8th, and 9th eggcrate
Flow distribution plate wear
Batwing wear
Vertical strap wear
PLP wear
Single axial indications

During the second RFO, a visual inspection of the secondary side of SG 2 was performed to ensure the integrity of the batwing and vertical strap supporting mechanisms. This limited inspection did verify that the upper eggcrate TSP, batwing, and vertical strap locations were acceptable and that no degradation to these supporting mechanisms had occurred.

Potential loose part (PLP) indications were identified during this outage. Two PLPs were identified in each SG; however, only one tube in SG 1 had a wear indication associated with the PLP. The tube with this PLP wear indication was plugged and stabilized (referred to by the licensee as staked).

Sludge profiling during this outage revealed minor sludge accumulation (average depth of 1" with a maximum of <2") on 138 tubes in SG 1 and 96 tubes in SG 2. The sludge was primarily located at the top of the tubesheet (TTS) with 2 tubes in SG 2 having sludge indications at the first TSP.

The tubes were primarily inspected with a 0.610" bobbin coil, with the smaller radius tubes being inspected with a smaller diameter probe. A rotating pancake coil (RPC) probe was used during this outage to characterize indications at various locations.

As a result of this inspection, 18 tubes were plugged in SG 1 and 87 tubes were plugged in SG 2; however, an additional 2 tubes in SG 1 and 3 tubes in SG 2 were inadvertently plugged. SG 1 had 99 tubes plugged and SG 2 had 170 tubes plugged following this outage.

e. Unit 2 RFO 3

During the third Unit 2 RFO, which began in October 1991, the initial inspection was planned to include 10913 tubes (100%) in SG 1 and a total of 6445 tubes (60%) in SG 2. These tubes were examined full length with the exception of some row 1 and row 2 tubes which were examined through the U-bend from both the hot and cold legs. The results of the SG 2 examination were category C-2, as defined in Technical Specification (TS) 4.4.4.2; therefore, approximately 700 additional tubes were inspected full length in SG 2. In addition, due to finding axial indications at the first hot leg TSP, the remaining tubes (2531 tubes) were inspected to the second TSP. The SG inspection began on 11/6/91 and concluded on

11/25/91. The major degradation mechanisms observed during the third RFO included:

- Cold leg corner wear
- Eggcrate wear - majority at the 7th, 8th, and 9th eggcrate
- Flow distribution plate wear
- Batwing wear
- Vertical strap wear
- PLP wear
- Single axial indications

The tubes were primarily inspected with a 0.610" bobbin coil, with the smaller radius tubes being inspected with a smaller diameter probe. A 3-coil RPC probe was used during this outage to characterize indications at various locations as described below.

As a result of this inspection, 15 tubes were plugged in SG 1; however, only 2 of the 15 tubes plugged exceeded the TS plugging limit. The SG 2 inspection resulted in 26 tubes being plugged. Of the 26 tubes plugged in SG 2, 18 tubes exceeded the TS plugging limit, 8 tubes were plugged for degradation. One of the tubes plugged was preventively plugged due to a PLP with no wear indicated which due to its orientation may have resulted in wear over the next cycle. Of the 7 axial indications, 6 were located at the first TSP and one was located in the tube free span between the 9th TSP and the batwing support. 8 tubes with PLP indications were identified in SG 1 and 21 tubes with PLP indications were identified in SG 2. Of the 8 tubes identified in SG 1 with PLP indications only four of the indications had associated wear and all four of these tubes were plugged. Of the 21 tubes identified in SG 2 with PLP indications only 5 had associated wear and all five of these tubes were plugged. SG 1 had 114 tubes plugged and SG 2 had 196 tubes plugged following this outage.

As a result of issuance of NRC Information Notice 90-49, "Stress Corrosion Cracking in PWR Steam Generator Tubes", 54 tubes in SG 1 and 86 tubes in SG 2 were examined using the multi-frequency RPC probe. The axial indications described previously were identified with the bobbin coil and were confirmed using the RPC probe. The random RPC sampling did not identify any degradation that was not detected by the bobbin coil.

f. Summary

To date, 114 tubes (1.0%) have been plugged in SG 1 and 196 tubes (1.8%) plugged in SG 2. A summary of the number of tubes plugged during each outage and the number of tubes plugged for various degradation mechanisms are given in the following tables.

SG Tube Plugging by Degradation Mechanism

MECHANISM	SG 1	SG 2
Factory	9	28
Baseline	6	4
Cold Leg Corner Wear	39	34
Vertical Strap Wear	31	33
Batwing Wear	12	47
7th through 9th Eggcrate TSP wear	7	31
Other wear	1	3
Axial Cracking at 1st TSP	0	6
Axial Cracking in Freespan	0	1
PLP cold leg	3	4
PLP hot leg	3	0
Other	3	5
TOTAL:	114	196

SG Tube Plugging by Outage

Outage	SG1	SG2
Baseline	15	32
Surveillance Testing	30	21
2R1	34	27
2R2	20	90
2R3	15	26

3. Evaluation of Degradation Mechanisms

a. Potential Loose Parts Evaluation

NRC Generic Letter 85-02, "Staff Recommended Actions Stemming from NRC Integrated Program for the Resolution of Unresolved Safety Issues Regarding Steam Generator Tube Integrity," requested a description of a licensee's overall program for assuring SG tube integrity and for steam generator tube rupture (SGTR) mitigation. Generic Letter 85-02, identified, in part, several staff recommended actions for the prevention and detection of loose parts. The licensee responded to Generic Letter 85-02 by letter dated June 21, 1985 (ANPP-32869-EEVB/JRP), and revised its response by letter dated March 27, 1987 (161-00107-JGH/BJA). In the revised response to Generic Letter 85-02, the licensee stated that, due to the physical location of the existing handholes, fiber optic inspection of the hot and cold leg tubesheet could not be conducted. In lieu of visual inspection, the licensee stated that it would use the eddy current testing results to identify potential loose parts and any loose part indication would be evaluated prior to plant restart.

Seven potential loose part (PLP) indications were identified in the Unit 2 SGs during the first RFO. Three PLP indications were in SG 1 and the remaining four PLP indications were in SG 2. Two (one in each SG) of the seven PLP indications had associated wear, the remaining five PLP indications had no wear associated with the tubes. The two PLP indications with associated wear were plugged during the first RFO. PLP indications detected on several adjacent tubes may be the result of one PLP (i.e., one loose part may cause indications on several adjacent tubes).

Fifteen PLP indications were identified in the Unit 2 SGs during the second RFO. Three PLP indications were identified in SG 1 and 12 in SG 2. Of the 15 PLP indications, ten were identified for the first time during this outage. One of the PLP indications in SG 1 had associated wear and was plugged during this RFO.

During the third RFO, additional PLP indications were identified by eddy current testing (ECT) in both SGs. A total of 29 PLP indications were identified during the third RFO, of which 8 were in SG 1 and 21 were in SG 2. Of the 29 PLP indications, 15 were identified for the first time during this outage. Four of the eight PLP indications in SG 1 had associated wear and were plugged. Four of the 21 PLP indications in SG 2 had associated wear and were plugged.

SG tube leakage due to PLP wear was identified by the licensee during the first Unit 3 RFO. The licensee verified the presence of the loose parts by visual examination through windows cut in the

SG tubes. The leaking and surrounding tubes were plugged and stabilized. Safety evaluations were performed by the licensee to assess the safety significance of these objects which were located above the flow distribution plate. The licensee also used this visual examination of the PLP to support the detection of PLPs with eddy current testing techniques.

Since visual observation or removal of foreign objects located on the secondary side of the SG cannot be readily performed in the CE System 80 SGs, the licensee performed a study, identified as document 02-MS-A72, "Evaluation of Foreign Objects in the Unit 2 Steam Generators at the Palo Verde Nuclear Generating Station." The objective of the study was to assess the foreign object/steam generator tube interactions based on the configuration and orientation of the objects as inferred from the ECT results, known SG geometry, and analytical and laboratory flow data. The evaluation also considered the safety implications associated with leaving the objects in the SGs through the next operating cycle, as well as options for the removal and tracking of the objects and existing leak detection capabilities at PVNGS. The conclusion of the study was that the continued presence of the identified foreign objects in the Unit 2 SGs was not a safety concern and did not constitute an unreviewed safety question. The licensee also concluded that the most likely effect of leaving the objects currently causing wear at the existing locations is continued wear and that plugging and stabilization of the affected tubes (i.e., those that have observed wear) would minimize the impact of future operation. In the event that a leak may develop as a result of a migrating loose part, the evaluation concluded that the leak would be detected early and would remain stable during either normal or postulated accident conditions and, therefore, would allow for a timely, controlled shutdown. The licensee also stated that the leak detection and leak response capabilities at PVNGS provide for as close as possible real-time information on the rate of increasing leakage and are consistent with the recommendations of NRC Information Notice 91-43, "Recent Incidents Involving Rapid Increases in Primary-to-Secondary Leak Rate."

The licensee requires material and parts accountability and traceability during the course of maintenance work activities on the secondary side of the SG. Maintenance on the primary side of the SG requires material accountability only during selected portions of the SG inservice inspection; however, a final closeout, to verify all foreign material has been removed, by a quality control inspector is required just prior to removing the wet dam and immediately after dry dam removal. At this point, material accountability associated with Zone III controls (as defined in procedure 30AC-9WP01) are implemented. Maintenance on the feedwater system does not require material accountability; however, the individual performing the maintenance is required to have training on foreign material exclusion (FME) and Zone III controls.

The inspector noted that since the first RFO, several additional loose parts have been identified on the secondary side of the SG. Introduction of these loose parts into the secondary side of the SG could be postulated to have come from several sources including introduction during initial SG fabrication, subsequent maintenance, or via operational sources (e.g., through the feedwater system). Due to the location in the SG tube bundle of several of these parts, the licensee considers the introduction of these parts during plant operations to be remote. The licensee believes that it is more likely that these parts have always been present and have been re-positioned or re-oriented in such a manner to allow detection via ECT. It was noted, however, that several of the indications, as a result of loose parts, are located in the periphery of the tube bundle and have grown from no detectable degradation (NDD) in one cycle to 65% through-wall in the next cycle.

The inspector also noted, that identification of PLPs is only possible if the PLP is electrically conductive and is in contact or extremely close proximity to the tube wall. PLPs not in close proximity to the tube wall may not be detected (e.g., PLPs in the annulus between the SG tubes and the SG shell).

The analysis of the eddy current data for the detection of PLPs is only performed by one analyst. In a typical SG tube inspection, two analysts review eddy current data and differences are resolved by a third analyst. The licensee believes the use of only one analyst to detect PLPs is satisfactory since SG tube wall degradation is not being monitored during this inspection and that only one frequency (20 kHz) is being examined during this inspection. The inspector noted that one PLP located in the interior of the tube bundle went from NDD to 85% through-wall in the course of one operating cycle.

Since the CE System 80 SGs at PVNGS do not have the capability for secondary side tubesheet visual inspection, removal of loose parts, or removal of sludge accumulations that may lead to SG tube degradation, the licensee has decided to install two-7" handholes on the secondary side of the SG during this outage to facilitate visual inspection, identification and retrieval of loose parts, and to provide the capability to remove sludge from the secondary side of the SG. Following installation of these handholes, the licensee currently plans to perform foreign object search and retrieval (FOSAR) and, if feasible, sludge sampling. Sludge lancing would be considered for future outages.

b. Batwing Wear

CE system 80 and 3410 SGs have experienced wear at the batwing support locations. Due to the lower flow rates through the central cavity for system 80 SGs as compared to the 3410 SGs, the wear was expected to be less severe and potentially non-existent. Eddy current inspections at PVNGS have identified a limited number of tubes with batwing wear indications. Tubes identified with batwing wear are plugged and stabilized. The licensee has implemented an administrative plugging criteria of 20% for wear at the inner cylinder batwing support area.

c. Cold Leg Corner Wear

A SG tube leak occurred in January 1987 in Unit 1. The leaking tube exhibited wear at the cold leg corner of the SG. The subsequent eddy current inspection identified several other tubes with wear indications in the cold leg corners of both SGs. Since Unit 2 was performing surveillance testing at this time, a limited inspection of this portion (i.e., cold leg corner) of the SG tube bundle in the Unit 2 SGs was performed. This inspection also revealed wear indications in the cold leg corners. The tube wear was limited to a small area of the tube bundle. An analysis by the licensee and CE determined that the tube wear could be attributed to the local high velocity cross flow field and the potential for high amplitude vibration in this area of the SG tube bundle. This wear phenomenon is unique to the System 80 economizer SG design.

As a result of detection of this phenomenon, all tubes within the high velocity region with any wear indications have been plugged and stabilized following each inspection. In addition, all tubes within the affected region in the Unit 3 SGs were preventively plugged (i.e., 60 tubes per SG) prior to commercial operation. The licensee currently plans to perform eddy-current inspections of unplugged tubes in and around the high velocity region each RFO to confirm all susceptible tubes have been identified and plugged. No unplugged tubes in the cold leg corners outside the preventively plugged pattern have exhibited wear indications consistent with cold leg corner wear during any of the subsequent Unit 3 inservice inspections. An administrative plugging criteria of 20% for cold leg corner wear has been implemented at PVNGS.

d. Vertical Strap and Upper Eggcrate Wear

Wear indications at the vertical and upper eggcrate supports (eggcrate TSPs 7, 8, and 9) have been observed in the Unit 2 SGs since the first RFO. Initial evaluation of this phenomenon by CE following the first RFO concluded that this type of wear was normal and expected given the number of tube-to-tube support plate interactions. CE further concluded that the wear would be expected to arrest after an initial wear-in period. During the second refueling outage, however, a significant increase in the number of tubes exhibiting vertical strap and upper eggcrate wear was observed. Tubes were plugged by the licensee based on wear rate projections. A visual inspection by CE and APS during the second RFO did not reveal any apparent cause of the wear problem. Vertical support and upper eggcrate wear is not as prevalent in the Unit 1 and Unit 3 SGs. CE and APS performed an evaluation of the differences in wear rates in the Unit 2 SGs including a review of the fabrication records, wear rates at other CE facilities, and a review of plant data differences. No definitive conclusions were made as a result of this evaluation.

Administrative plugging criteria have been developed by the licensee for vertical strap wear. The licensee stated that a study (Letter V-CE-35658 dated April 21, 1988) performed by the licensee and CE demonstrates that 63% to 64% through-wall defects meet Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes" structural criteria. In addition, for vertical strap wear, burst tests performed by CE (CE Report CENC 1698) indicate 70% through-wall defects meet Regulatory Guide 1.121 criteria. The study assumed that wear due to tube-to-tube support plate interactions will progress at no greater than a constant volumetric wear rate. The licensee considered this to be a conservative assumption since the relatively stiff, interlocked support grid straps cannot follow the tube contact surface as the wear progresses. Based on the studies performed by the licensee and CE, the licensee decided that indications greater than or equal to 35% through-wall, for all tubes previously examined with no indications detected or not inspected, will be plugged. However, if a tube exhibiting vertical strap wear had a previous indication greater than or equal to 10% through-wall and was between 35% and 39% through-wall it would not require plugging. The plugging limits referred to above are administrative limits, since the licensee believes the 40% Technical Specification plugging limit is adequate to meet Regulatory Guide 1.121 criteria for this degradation mechanism. Based on the test results, the studies indicated that for worst case "flat" wear on the tube surface due to fretting against either a one inch or one-half inch bar, the tube will develop leakage gradually and not suddenly burst due to operating differential pressure across the tube wall.

e. Axial Cracking

During the third RFO, 7 axial indications were found in Unit 2. Six of the indications were located at the first TSP; whereas, the seventh indication was located in the free span of the tube between the 9th TSP and the batwing support. As a result of the initial finding of an axial crack-like indication at the TSP, the licensee initiated Engineering Evaluation Request (EER) Number 91-RC-134. As a result of these findings and the evaluation provided in the above referenced EER, several short term actions were taken, including: (1) the ECT scope was increased to include 100% of the first hot leg TSP and approximately 70% of the tubes full length; (2) confirmatory RPC probe inspections were performed for these indications; (3) a re-review of SG 1 data was performed; and (4) the industry database (EPRI) was consulted and a third party review was utilized. As a result of these short term actions, a total of 7 tubes were identified with axial indications. Of the 6 tubes at the first TSP, three were approximately 80% through-wall and the remaining three were less than 40% through wall. The six axial crack-like indications at the first TSP were all located in tubes with the smaller diametral clearances. All of the axial indications were plugged. The seventh axial crack like indication, located between the 9th TSP and the batwing support, was also plugged. This indication was approximately 1.07" long and 75% through-wall.

EER 91-RC-134, initiated on November 19, 1991, has not yet been closed out pending a planned SG tube pull analysis intended to characterize the cracking phenomenon. No analysis of the growth rate of these indications was performed due to the small number of indications (i.e., 7 indications). The staff notes that the growth rates for several of these indications appears to be excessive, growing to approximately 80% through-wall in one operating cycle. The indication in the tube free span (Row 117 Column 154) essentially went from NDD to 1.07" long and 75% through-wall in one operating cycle. No analysis on the pressure retaining capability of this tube was performed. Note that no other axial crack-like indications have been noticed in the tube free span or at the TSPs in either Units 1 and 3.

Although all of the tubes exhibiting axial crack-like indications were plugged, no formal evaluation on the safety significance of these indications was performed (the licensee did perform several actions including evaluation of industry experience and ensuring inspection scope was adequate). The axial cracks at the first TSP are not uncommon and can be postulated to have occurred due to concentration of contaminants in the crevice between the tube and TSP; however, the presence of free span cracking would not be expected. Note that preliminary indications on the location of the leak indicate that it is in the general vicinity of the location of the detected axial crack. However, it is also noted that batwing, vertical strap, and PLP wear are also prevalent in this location of the SG. However, studies performed by CE and the licensee indicated that wear indications in this area of the SG would not be expected to rupture (i.e., would expect small stable leak).

Technical Specification 6.5.3.4.f requires significant operating abnormalities or deviations from normal and expected performance of unit equipment that affect nuclear safety to be reviewed by the Offsite Safety Review Committee. A formal safety review was not performed for the axial crack located in the tube free span on tube R117C154. In addition, 10 CFR 50.72(a)(2)(i) requires, in part, notification of the NRC as soon as practical and in all cases within four hours of the occurrence of any event, found while the reactor is shut down, that, had it been found while the reactor was in operation, would have resulted in the nuclear power plant, including its principal safety barriers, being seriously degraded or being in an unanalyzed condition that significantly compromises plant safety. Since no safety evaluation was performed for the crack-like indication found above the 9th TSP on tube R117C154, the licensee did not verify that the principal safety barrier was not seriously degraded.

f. SG Tube Plug Evaluation

Three different types of plugs have been used in removing SG tubes from service in Unit 2. The plugs in use include the CE welded plugs, Westinghouse mechanical plugs, and B&W mechanical plugs. The licensee stated that the Westinghouse mechanical plugs in Unit 2, identified in NRC Bulletin 89-01, "Failure of Westinghouse Steam Generator Tube Mechanical Plugs," have been replaced. In addition the licensee stated that none of the plugs identified in NRC Information Notice 89-65, "Potential for Stress Corrosion Cracking in Steam Generator Tube Plugs Supplied by

Babcock and Wilcox" are currently installed in the Unit 2 SGs.

During the process of replacement of one of the Alloy 600 Westinghouse mechanical plug on the hot leg side of Row 78 Column 21, during the second RFO of Unit 2, it was noticed that the plug top had experienced primary water stress corrosion cracking and had released. The plug top became lodged in the tube transition area. An evaluation was performed to determine the acceptability of leaving the plug top in place. The analysis of the scenario of the plug top being propelled downward and impacting the newly installed SG tube plug was performed. Based on this analysis a 17-inch stabilizer was installed to limit the potential loads on the newly installed plug. This stabilizer was intended to eliminate any adverse affects caused by the fractured tube plug top that remains in the tube. This analysis is documented in EER 90-RC-068.

Several instances of tube plug leakage have been observed in the SGs at PVNGS. The leakage has primarily been attributed to CE welded plugs. Following completion of the first Unit 1 RFO eddy current testing (Fall 1987), several CE welded plugs installed during the previous outage due to SG tube leakage (January 1987) were found to have evidence of leakage. All affected tubes were repaired. Following the second Unit 1 RFO eddy current testing, several of the CE welded plugs installed during the January 1987 outage and subsequently repaired during the Unit 1 second RFO were again found leaking via pressurized leak tests. Affected tubes were repaired. The leaking CE plug welds were determined to be the result of poor accessibility due to the constraints presented by the divider plate, curvature of the bowl, and the presence of the patch plate and bolts. The patch plates are located where the corners of the primary channel head divider plate meets the channel bowl and stay cylinder. The patch plates are bolted to the divider plate. The reason for the difficulty in plugging in this region is due to the fact that direct vertical access to the subject tubes can not be readily achieved due to the physical geometry at this location. The Westinghouse and B&W mechanical plugs can not be installed due to their geometry (e.g., the B&W plug is too long to be inserted into the tube at this location) and/or manipulator limitations. The patch plates and their associated bolts limit access to approximately 20 tubes per SG.

4. SG Inspections

a. Background

NRC guidance on eddy current testing of SG tubes is contained within Regulatory Guide 1.83, "Inservice Inspection of PWR Steam Generator Tubes." In practice, the NRC has endorsed the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) as the minimum requirements for performing eddy current testing.

b. Inservice Inspections at PVNGS

The utility typically performs a bobbin coil examination of the SG tubing with a 0.610" or 0.590" diameter probe. Supplemental inspections are performed typically with a 3-coil RPC. The utility has taken positive action in response to NRC Information Notice 90-49, "Stress Corrosion Cracking in PWR Steam Generator Tubes," and Information Notice 91-67, "Problems with the Reliable Detection of Intergranular Attack (IGA) of Steam Generator Tubing," by performing a limited number of random RPC inspections and by ensuring that all indications are identified regardless of signal amplitude or signal-to-noise ratio. In part, due to the issuance of NRC Information Notice 92-80, "Operation with Steam Generator Tubes Seriously Degraded," the licensee plans to perform RPC examinations of a minimum of 10% of the tubes at the expansion transition and first tube support plate locations on the hot leg side.

The speed at which the bobbin coil is pulled through the tubes in conjunction with the computer sampling rate can affect system sensitivity to various types of flaws. In order to ensure that appropriate sensitivity of the equipment used at PVNGS is consistent with the ASME Code specified sensitivity, the utility performed an analysis (109-00392-RAK/JBS) to support the use of a 24 in/sec probe pull speed with a computer sampling rate of 800 samples/sec. The results of the 24 in/sec probe pull speed were compared to probe pull speeds of 12 in/sec with a computer sampling rate of 400 samples/sec. The eddy current probe speed test evaluated the signals generated from the calibration standard. The eddy current probe speed test, however, did not evaluate the change in noise generated by the increased probe speed nor did it evaluate the ability to detect and characterize actual flaws in the SG tubing at PVNGS (note that some eddy current probe speed test data from actual SG tubing inspections were reviewed from D.C. Cook Unit 1 and a Pensacola fabrication facility).

Conclusions

The AIT concluded that the licensee had implemented a strong program for assessing their steam generators and their integrity. This was evidenced by the fact that the licensee performs much more examination of their SGs than they were required to perform and their extensive involvement in industry groups sharing information on SG integrity and problems.

5. Outage Plans

a. Inspection Scope and Basis

As a result of the SGTR, the licensee currently plans to perform the following SG tube inspections:

- 100% Bobbin coil inspection of the tubing in each SG

- RPC probe inspection of a minimum of 10% of the SG tubes at the expansion transition and first TSP locations on the hot leg side

Additional RPC inspections will be performed as necessary to ensure adequate structural integrity of the tubing. The basis for these inspections is to ensure that the degradation mechanisms observed at PVNGS are properly identified and that degradation mechanisms observed by other utilities and vendors are also identified, if present. The degradation mechanisms observed at PVNGS include:

- Axial cracking at the top of the tubesheet (Unit 1)
- Axial cracking found at 1st TSP (flow distribution baffle) in Unit 2
- Axial cracking found between the 9th TSP and the batwing support

- Wear at the cold leg corners, batwings, and vertical straps
- Loose parts with and without associated wear

Some of the other degradation mechanisms observed by other utilities and vendors include:

- Circumferential and axial cracking at the tubesheet and/or TSPs
- Denting and cracking next to the stay rods
- Cracking in the short radius U-bends (rows 1 and 2)
- Crevice cracking or attack (tubes with no expansion)

b. Potential Root Causes

Although the root cause can not be determined until the SG tubing is accessible, several possible root causes are being explored by the licensee. The type of degradation and the proposed inspection actions are listed below. The information presented below for proposed inspections is dependent on the nature of the degradation mechanism and may change as the inspection proceeds:

- Circumferential cracking (fatigue assisted):

  No circumferential cracking has been observed at PVNGS. Possible inspection activities include: Leak testing of the SG, 100% RPC of both SGs, SG tube pull

- Axial cracking:

  Axial cracking has been observed at the first TSP and between the 9th TSP and the batwing support. Axial cracking has also been observed in Units 1 and 3 at the tube-to-tubesheet weld and in the portion of tube located in the tubesheet for unexpanded tubes. Possible inspection activities include leak testing of the SGs, 100% bobbin coil inspection, and a SG tube pull.

- Fatigue assisted manufacturing or wear defect (e.g., North Anna Unit 1 SGTR):

  Wear has been observed in the cold leg corner, batwing support, and vertical strap locations. Possible inspection activities include leak testing of the SGs, 100% bobbin coil inspection, supplemental RPC inspections, and a SG tube pull.

- Loose part interaction (Ginna/Prairie Island):

  As noted previously, several loose parts have been identified in the Unit 2 SGs. Possible inspection activities include leak testing of the SGs, 100% bobbin coil inspection, RPC inspection of PLP locations, and foreign object search and retrieval (FOSAR) after handhole installation is complete.

- Plug failure:

  CE welded plugs - Numerous CE welded plugs are installed in the Unit 2 SGs. Leakage from these plugs have been observed in the past as described previously. Depending on the nature of the failure, an evaluation of the integrity of other CE welded plugs would be required.

  B&W Mechanical plugs - No leakage has been observed from B&W plugs installed at PVNGS Units. Possible inspection activities being explored by the licensee include leak testing of the SG and ECT profile analysis.

  Westinghouse mechanical plugs - No leakage has been observed from these plugs; however, one plug cap from a replaced Alloy 600 Westinghouse mechanical plug in SG 1 was not removed from tube R78C21. Possible inspection activities being explored by the licensee include leak testing of the SG and additional inspections to be determined.

Near the end of the AIT inspection, while draining the reactor coolant s[illegible]G 2 water level began decreasing, as ex[illegible], due to secondary-to-primary leakage through the rupture location. The level in SG 2 stabilized at approximately 60% on the SG wide range indicator. This level indication indicates that the leak may be above the 9th TSP. Degradation mechanisms observed in this area include batwing and vertical strap wear, PLP wear, and axial cracking. The potential for fatigue assisted cracking has not been ruled out even though none has been observed at this area. During discussions on the potential causes of the rupture, the licensee stated that two indications at the batwing support in SG 2 (R134C97 with 85% wear and R112C151 with 36% wear) were evaluated in the prior outage as PLP wear indications but that consideration was given during that outage to calling them axial crack-like indications. The licensee also stated that in their best judgment these indications are PLPs.

The current action plan includes the following:

- Visual leak test to identify all of the leaking tubes and the approximate elevation of the defect(s).
- Bobbin coil inspection to determine the location of the defect and characterize the flaw. A historical review of the eddy current data will be performed for the faulted tube(s).
- RPC inspection for further flaw characterization.
- Video probe inspection of the faulted tube for further flaw characterization.
- Destructive examination of the faulted tube is being considered. Feasibility of a tube pull depends on the nature of the flaw and the location of the affected tube.

6. <u>Hydrogen Control</u>

PVNGS operates with a hydrogen overpressure in the reactor coolant to ensure that no dissolved oxygen remains in the water. At the time of the SGTR, the equilibrium concentration of hydrogen in the primary coolant was approximately 27.4 cc/kg. During the early stages of the SGTR, sufficient loss of reactor coolant into SG 2 resulted in the equilibrium concentration of hydrogen decreasing. Oxygenated water can enter the reactor coolant system from the Refueling Water Tank (RWT).

A generally accepted guideline is that a mixture of hydrogen and oxygen gasses in ratios in excess of 4% hydrogen and 5% oxygen represents a flammable condition. Mixtures of these gasses in ratios of 18% to 59% hydrogen and >5% oxygen will detonate in the presence of an ignition source. The potential presence of a flammable and/or explosive mixture in the SG represents a significant safety and/or operational concern. Although post-event calculations (documented in Calculation No. 02-MC-SG-200) performed by the licensee show that the hydrogen concentration in the SG2 void space was less than that required for combustion, the lack of recognition of the potential for such a mixture to exist represents a technical/training weakness. The presence of hydrogen in the SG as a result of a SGTR was identified in NUREG-0909, "NRC Report on the January 25, 1982 Steam Generator Tube Rupture at R. E. Ginna Nuclear Power Plant," and the importance of proper control of hydrogen levels in a SG following a SGTR was specifically addressed in NRC augmented inspection team report nos. 50-338/87-24 and 50-339/87-24 which describe the North Anna Unit 1 SGTR in July 1987. The NRC had not yet promulgated any generic information on these events to the industry.

J. Exit Interview

The AIT met with licensee management at the conclusion of the inspection on March 25, 1993. The scope and findings of the AIT were summarized. The licensee acknowledged the team's observations and findings.

APPENDIX A

PERSONS CONTACTED

*R. Adney, Unit 3 Plant Manager
*J. Bailey, Director, Nuclear Safety and Licensing
*T. Barsuk, Supervisor, Onsite Emergency Planning
M. Baughman, Requalification Supervisor
*H. Beiling, Manager, Emergency Planning
D. Bernier, Regulatory Affairs
T. Bierney, Loose Parts Detection Engineer
B. Blackmore, HPSI System Engineer
D. Blackson, Central Maintenance Manager
*T. Bradish, Manager, Nuclear Regulatory Affairs
J. Brannon, Reactor Operator, Unit 2
A. Briese, STA
J. Brown, NED-Mechanical
G. Bucci, Chemistry Advisor, Site Chemistry
D. Burns, Shift Supervisor, Unit 1
R. Buzard, IIT Team Leader
P. Coffin, Engineer, Nuclear Regulatory Affairs
D. Cole, Sargent, PVNGS Security
*W. Conway, Executive Vice President
D. Coxon, Shift Supervisor, Unit 1
C. Day, Supervisor Plant Engineering I&C
W. Dehaven, Reactor Operator, Unit 2
D. Ensign, Shift Supervisor, Unit 2
*R. Flood, Plant Manager, Unit 2
*L. Florence, IIT Team Member
*H. Freeman, NRC Resident Inspector
D. Gabel, QC Supervisor
D. Gibson, RMS Technician, Unit 2
D. Goodwin, Chemistry Supervisor
*D. Gouge, General Manager, Plant Support
B. Grabo, Supervisor, Nuclear Regulatory Affairs
*K. Hamlin, Director, Nuclear Safety
D. Hansen, ISI Engineer
J. Hughes, Sargent, PVNGS Security
*P. Hughes, General Manager, Radiation Protection
*W. Ide, Plant Manager, Unit 1
R. Jenkins, Chemistry Technical Advisor
L. Johnson, Manager, Unit 2 Chemistry
T. Johnson, Reactor Operator, Unit 2
T. Jury, Shift Supervisor, Unit 2
D. Kanitz, Engineer, Nuclear Regulatory Affairs
S. Karimi, Engineer, Nuclear Regulatory Affairs
H. Lesan, Sr. Advisor, RMS/Effluents
*J. Levine, Vice President, Nuclear Production
R. Linthicum, PRA
*J. Lutton, Emergency Response Program Manager, Arizona Radiation Regulatory Agency
N. Mackenzie, Reactor Operator, Unit 2
M. Mann, SOED/HPES
H. Maxwell, Vibration Engineer

*C. McClain, Manager, Technical Training
M. McEwan, HPSI System Engineer
M. Melton, NED Metallurgist
G. Michael, Nuclear Regulatory Affairs
R. Middleton, Operations Supervisor, Unit 2
*L. Miller, Chief, Reactor Safety Branch, NRC/Region V
T. Murphy, Supervisor, RMS/Effluents
B. Nunez, Operations Training Manager
*G. Overbeck, Site Director, Technical Support
K. Parrish, Senior Engineer, Safety Analysis
N. Povio, Reactor Operator, Unit 2
T. Price, Performance Engineer
M. Radspinner, NED Supervisor
M. Reid, Supervisor, Safety Analysis
H. Riley, Root Cause Manager
*F. Ringwald, NRC Resident Inspector
K. Roberson, Senior Compliance Engineer
R. Rogalski, Engineer, Nuclear Regulatory Affairs
*C. Russo, Manager, Quality Control
J. Scott, Unit 3 Assistant Plant Manager
P. Shankar, Consulting Engineer, Safety Analysis
B. Simmons, Shift Technical Advisor
J. Scott, Site Chemistry
*B. Simpson, Vice President, Nuclear Engineering
M. Shea, Manager, Unit 2 Radiation Protection
J. Skrtich, Reactor Operator, Unit 2
*J. Sloan, NRC Resident Inspector
V. Smith-Hopkins, Plant Engineering
D. Sneed, Supervisor, Unit 2 Chemistry
W. Sneed, Manager, Unit 3 Radiation Protection
R. Sorensen, Manager, Site Chemistry Support
L. Speight, Shift Supervisor, Unit 2
*R. Stevens, Director, Regulatory Affairs
D. Swan, Shift Supervisor, Unit 3, Initial Event and Shutdown Crew
K. Sweeney, NED Engineer Chairman, Steam Generator Working Group
N. Thibodaux, Diesel Generator Engineer
G. Turner, Industry Operating Experience Engineer
N. Turley, Engineer, Nuclear Regulatory Affairs
R. Warner, Unit 2 STA
R. Wells, Lead Chemistry Technician, Unit 2
*P. Wiley, Manager, Unit 2 Operations
R. Wilson, Reactor Operator, Unit 2
J. Wolfe, Supervisor, Unit 2 Chemistry
J. Young, Independent Safety Engineer

* Denotes Principal Exit Interview Attendee

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION V
1450 MARIA LANE
WALNUT CREEK, CALIFORNIA 94596-5368

MAR 15 1993

MEMORANDUM FOR: D. F. Kirsch, Team Leader
Palo Verde Unit 2

FROM: J. B. Martin, Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER - STEAM GENERATOR TUBE LEAK AT PALO VERDE UNIT 2

After being briefed on the March 14, 1993 steam generator tube leak at Palo Verde Unit 2, NRR, AEOD, and Region V senior management determined that an Augmented Inspection Team (AIT) inspection should be conducted at Palo Verde Unit 2 to verify the circumstances and evaluate the significance of this event.

You have been designated as the Team Leader. Enclosed is the charter for the Augmented Inspection Team delineating the scope of this inspection. The inspection is to be conducted in accordance with NRC Directive 8.3; NRC Inspection Manual, Chapter 0325; NRC Inspection Procedure 93800; Incident Investigation Manual, NUREG 1303; and this memorandum.

for J. B. Martin
Regional Administrator

Enclosure:
(1) Augmented Inspection Team Charter

cc:
J. Taylor, EDO
J. Sniezek, EDO
W. Bateman, EDO
T. Murley, NRR
J. Partlow, NRR
M. Virgilio, NRR
C. Rossi, NRR
A. Chaffee, NRR
T. Quay, NRR
C. Trammell, NRR
F. Miraglia, NRR
W. Russell, NRR
D. Kunihiro, RV
J. Richardson, NRR
A. Thadani, NRR
B. Grimes, NRR
J. Roe, NRR
E. Jordan, AEOD
D. Ross, AEOD
B. Faulkenberry, RV
K. Perkins, RV
R. Scarano, RV
S. Richards, RV
H. Wong, RV
G. Cook, RV
J. Sloan, RV

Enclosure (1)

AUGMENTED INSPECTION TEAM CHARTER
PALO VERDE UNIT 2 STEAM GENERATOR TUBE LEAK
ON MARCH 14, 1993

The Augmented Inspection Team (AIT) is to perform an inspection to accomplish the following:

1. Develop a complete description of the event:

   a. Develop a detailed sequence of events. Include a discussion of any precursor events, such as whether previous steam generator leakage had been properly evaluated and trended.

   b. Identify any equipment failures that occurred.

   c. Assess the possible cause of the steam generator tube leak. Specifically consider steam generator tube inspection results, water chemistry data, and whether loose parts in the steam generator caused the leak.

   d. Determine whether the cause of the Unit 2 steam generator tube leak is an operational safety concern for the Unit 1 and 3 steam generators.

2. Verify and evaluate the licensee's immediate actions following this event, including the timeliness of the leak isolation.

3. Assess licensee's management involvement and control during the event, and in corrective actions subsequent to the event.

4. Identify and evaluate the diagnostic, emergency operating, and functional recovery procedures used by the licensee during the event. Determine the effectiveness of, and adherence to, these procedures as they relate to the event. Assess operator actions, operator use of symptom based procedures, and whether the operator's procedure compliance impacted operator response.

5. Evaluate the human factors aspects associated with this event, including:

   a. Team work, command, control and communications during the event.

   b. Human performance factors such as staffing, training, overtime, stress, and human systems interface.

   c. Any significant human errors that occurred during the event and during event recovery.

   d. Effectiveness of the plant reference simulator to adequately model the event.

6. Review the licensee's radiological response to the incident by evaluating the measurement of, and dose impact of radioactivity released. Also

review the in-plant assessment of radiological dose projections, radiological controls and radiological monitoring systems exercised in response to the event. Evaluate the appropriateness and timeliness of the licensee's actions to limit onsite and offsite exposure.

7. Assess the adequacy of the licensee's emergency preparedness response to the event (including classification, notification, manning, timeliness of manning, information updates and coordination). If the event was improperly classified, determine why.

8. Document any observations concerning the NRC's response to the event.

9. Provide a Preliminary Notification upon initiation of the inspection and an update at the conclusion of the inspection.

10. Prepare a special inspection report documenting the results of the above activities within 30 days of the start of the inspection.

binder revised, incorporating KSI comments

RICHARDS SAR PERKINS SAR for SCARANO JAW MARTIN BF

4/15/93 4/15/93 4/15/93 4/16/93

REQUEST COPY	REQUEST COPY	REQUEST COPY	REQUEST COPY
YES ☒ NO ☐	YES ☒ NO ☐	YES ☒ NO ☐	YES ☐ NO ☒

to Wenslawski

SEND TO DCS	SEND TO PDR
YES ☒ NO ☐	YES ☒ NO ☐

IE01

bcc w/enclosure:
James Taylor, Executive Director of Operations, EDO
James H. Sniezek, Deputy Executive Director Nuclear Reactor Regulation, Regional Operations and Research, OEDO
M. Lesser, Region V Contact, OEDC
David A. Ward, Chairman, Advisory Committee on Reactor Safeguards (ACRS)
The Commissioners:
Ivan Selin, Chairman
James R. Curtiss
E. Gail de Planque
Forrest J. Remick
Kenneth C. Rogers
Charles Trammell, III, Project Manager, NRR
Alfred E. Chaffee, Chief, Events Assessment Branch, Div. Operational Events Assessment, NRR
Document Control Desk (Office of Information Resources Management), NRR
Thomas E. Murley, Director, NRR
F. J. Miraglia, Deputy Director, NRR
J. G. Partlow, Associate Director for Projects, NRR
J. W. Roe, Director, Div. Reactor Projects--Regions III, IV, and V, NRR
W. T. Russell, Associate Director for Inspection and Technical Assessment, NRR
B. K. Grimes, Director, Div. of Operational Events Assessment, NRR
C. E.Rossi, Div. of Reactor Inspection and Safeguards, NRR
B. A. Boger, Director, Div. of Licensee Performance and Quality Evaluation, NRR
A. C. Thadani, Director, Div. of Systems Technology, NRR
M. J. Virgilio, Assistant Director, Regions IV & V Reactors, NRR
J. E. Richardson, Director, Div. of Engineering Technology, NRR
T. R. Quay, Director, Project Directorate V, NRR
Edward L. Jordan, Director, AEOD
Denwood F. Ross, Deputy Director, AEOD
Director, DRP, RI, II, III, IV

Region V/dot

Dkirsch	Wlyon	Pqualls	Tsundsmo
/ /93	3/31/93	/ /93	/ /93
REQUEST COPY	REQUEST COPY	REQUEST COPY	REQUEST COPY
YES / NO	YES / NO	YES / NO	YES / NO
Kkarwoski	Rbocanegra	Kihnen	Ggalletti
/ /93	/ /93	/ /93	/ /93
REQUEST COPY	REQUEST COPY	REQUEST COPY	REQUEST COPY
YES / NO	YES / NO	YES / NO	YES / NO

bcc w/enclosure:
James Taylor, Executive Director of Operations, EDO
James H. Sniezek, Deputy Executive Director Nuclear Reactor Regulation, Regional Operations and Research, OEDO
C. Cowgill, Region V Contact, OEDO
Paul Shewmon, Chairman, Advisory Committee on Reactor Safeguards (ACRS)
The Commissioners:
    Ivan Selin, Chairman
    James R. Curtiss
    E. Gail de Planque
    Forrest J. Remick
    Kenneth C. Rogers
Charles Trammell, III, Project Manager, NRR
Alfred E. Chaffee, Chief, Events Assessment Branch, Div. Operational Events Assessment, NRR
Document Control Desk (Office of Information Resources Management), NRR
Thomas E. Murley, Director, NRR
F. J. Miraglia, Deputy Director, NRR
J. G. Partlow, Associate Director for Projects, NRR
J. W. Roe, Director, Div. Reactor Projects--Regions III, IV, and V, NRR
W. T. Russell, Associate Director for Inspection and Technical Assessment, NRR
B. K. Grimes, Director, Div. of Operating Reactor Support, NRR
C. E. Rossi, Director, Div. of Reactor Inspection and Licensee Performance, NRR
B. A. Boger, Director, Div. of Reactor Controls and Human Factors, NRR
A. C. Thadani, Director, Div. of Systems Safety and Analysis, NRR
M. J. Virgilio, Assistant Director, Regions IV & V Reactors, NRR
J. E. Richardson, Director, Div. of Engineering, NRR
T. R. Quay, Director, Project Directorate V, NRR
Edward L. Jordan, Director, AEOD
Denwood F. Ross, Deputy Director, AEOD
Director, DRP, RI, II, III, IV

Region V/dot	See attached	See attached	See attached
Dkirsch K	Wlyon	Pqualls	Tsundsmo
3/31/93	3/31/93	4/1/93	3/31/93
REQUEST COPY	REQUEST COPY	REQUEST COPY	REQUEST COPY
YES / NO	YES / NO	YES / NO	YES / NO
See attached	See attached	See attached	See attached
Kkarwoski	Rbocanegra	Kihnen	Ggalletti
3/31/93	4/1/93	4/2/93	4/1/93
REQUEST COPY	REQUEST COPY	REQUEST COPY	REQUEST COPY
YES / NO	YES / NO	YES / NO	YES / NO

bcc w/enclosure:
James Taylor, Executive Director of Operations, EDO
James H. Sniezek, Deputy Executive Director Nuclear Reactor
  Regulation, Regional Operations and Research, OEDO
M. Lesser, Region V Contact, OEDO
David A. Ward, Chairman, Advisory Committee on Reactor Safeguards
  (ACRS)
The Commissioners:
     Ivan Selin, Chairman
     James R. Curtiss
     E. Gail de Planque
     Forrest J. Remick
     Kenneth C. Rogers
Charles Trammell, III, Project Manager, NRR
Alfred E. Chaffee, Chief, Events Assessment Branch, Div.
  Operational Events Assessment, NRR
Document Control Desk (Office of Information Resources
  Management), NRR
Thomas E. Murley, Director, NRR
F. J. Miraglia, Deputy Director, NRR
J. G. Partlow, Associate Director for Projects, NRR
J. W. Roe, Director, Div. Reactor Projects--Regions III, IV,
and V, NRR
W. T. Russell, Associate Director for Inspection and Technical
  Assessment, NRR
B. K. Grimes, Director, Div. of Operational Events Assessment,
  NRR
C. E.Rossi, Div. of Reactor Inspection and Safeguards, NRR
B. A. Boger, Director, Div. of Licensee Performance and Quality
  Evaluation, NRR
A. C. Thadani, Director, Div. of Systems Technology, NRR
M. J. Virgilio, Assistant Director, Regions IV & V Reactors, NRR
J. E. Richardson, Director, Div. of Engineering Technology, NRR
T. R. Quay, Director, Project Directorate V, NRR
Edward L. Jordan, Director, AEOD
Denwood F. Ross, Deputy Director, AEOD
Director, DRP, RI, II, III, IV

Region V/dot

DKirsch / /93 REQUEST COPY YES / NO	Wlyon / /93 REQUEST COPY YES / NO	Pqualls / /93 REQUEST COPY YES / NO	Tsundsmo / /93 REQUEST COPY YES / NO
Kkarwoski 3 /31/93 REQUEST COPY YES / NO	Rbocanegra / /93 REQUEST COPY YES / NO	Kihnen / /93 REQUEST COPY YES / NO	Ggalletti / /93 REQUEST COPY YES / NO

bcc w/enclosure:
James Taylor, Executive Director of Operations, EDO
James H. Sniezek, Deputy Executive Director Nuclear Reactor Regulation, Regional Operations and Research, OEDO
C. Cowgill, Region V Contact, OEDO
David A. Ward, Chairman, Advisory Committee on Reactor Safeguards (ACRS)
The Commissioners:
Ivan Selin, Chairman
James R. Curtiss
E. Gail de Planque
Forrest J. Remick
Kenneth C. Rogers
Charles Trammell, III, Project Manager, NRR
Alfred E. Chaffee, Chief, Events Assessment Branch, Div. Operational Events Assessment, NRR
Document Control Desk (Office of Information Resources Management), NRR
Thomas E. Murley, Director, NRR
F. J. Miraglia, Deputy Director, NRR
J. G. Partlow, Associate Director for Projects, NRR
J. W. Roe, Director, Div. Reactor Projects--Regions III, IV, and V, NRR
W. T. Russell, Associate Director for Inspection and Technical Assessment, NRR
B. K. Grimes, Director, Div. of Operational Events Assessment, NRR
C. E.Rossi, Div. of Reactor Inspection and Safeguards, NRR
B. A. Boger, Director, Div. of Licensee Performance and Quality Evaluation, NRR
A. C. Thadani, Director, Div. of Systems Technology, NRR
M. J. Virgilio, Assistant Director, Regions IV & V Reactors, NRR
J. E. Richardson, Director, Div. of Engineering Technology, NRR
T. R. Quay, Director, Project Directorate V, NRR
Edward L. Jordan, Director, AEOD
Denwood F. Ross, Deputy Director, AEOD
Director, DRP, RI, II, III, IV

Region V/dot

	See attached		TBS section II only
Dkirsch K	Wlyon	Pqualls	Tsundsmo
3/31/93	3/31/93	4/1/93	3/31/93
REQUEST COPY	REQUEST COPY	REQUEST COPY	REQUEST COPY
YES / NO	YES / NO	YES / NO	YES / NO
See attached		DFK BY TELECON 4/2/93	See attached
Kkarwoski	Rbocanegra	Kihnen	Ggalletti
3/31/93	4/1/93	4/2/93	4/1/93
REQUEST COPY	REQUEST COPY	REQUEST COPY	REQUEST COPY
YES / NO	YES / NO	YES / NO	YES / NO

bcc w/enclosure:
James Taylor, Executive Director of Operations, EDO
James H. Sniezek, Deputy Executive Director Nuclear Reactor Regulation, Regional Operations and Research, OEDO
M. Lesser, Region V Contact, OEDO
David A. Ward, Chairman, Advisory Committee on Reactor Safeguards (ACRS)
The Commissioners:
- Ivan Selin, Chairman
- James R. Curtiss
- E. Gail de Planque
- Forrest J. Remick
- Kenneth C. Rogers

Charles Trammell, III, Project Manager, NRR
Alfred E. Chaffee, Chief, Events Assessment Branch, Div. Operational Events Assessment, NRR
Document Control Desk (Office of Information Resources Management), NRR
Thomas E. Murley, Director, NRR
F. J. Miraglia, Deputy Director, NRR
J. G. Partlow, Associate Director for Projects, NRR
J. W. Roe, Director, Div. Reactor Projects--Regions III, IV, and V, NRR
W. T. Russell, Associate Director for Inspection and Technical Assessment, NRR
B. K. Grimes, Director, Div. of Operational Events Assessment, NRR
C. E.Rossi, Div. of Reactor Inspection and Safeguards, NRR
B. A. Boger, Director, Div. of Licensee Performance and Quality Evaluation, NRR
A. C. Thadani, Director, Div. of Systems Technology, NRR
M. J. Virgilio, Assistant Director, Regions IV & V Reactors, NRR
J. E. Richardson, Director, Div. of Engineering Technology, NRR
T. R. Quay, Director, Project Directorate V, NRR
Edward L. Jordan, Director, AEOD
Denwood F. Ross, Deputy Director, AEOD
Director, DRP, RI, II, III, IV

Region V/dot

Dkirsch	Wlyon	Pqualls	Tsundsmo
/ /93	/ /93	/ /93	/ /93
REQUEST COPY	REQUEST COPY	REQUEST COPY	REQUEST COPY
YES / NO	YES / NO	YES / NO	YES / NO
Kkarwoski	Rbocanegra	Kihnen	Gcwalina
/ /93	/ /93	/ /93	03/31/93
REQUEST COPY	REQUEST COPY	REQUEST COPY	REQUEST COPY
YES / NO	YES / NO	YES / NO	YES / NO