ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/95-98
50-368/95-98

Licenses: DPR-51
NPF-6

Licensee: Entergy Operations, Inc.
1448 S.R. 333
Russellville, Arkansas

Facility Name: Arkansas Nuclear One, Units 1 and 2

Inspection At: Russellville, Arkansas

Inspection Conducted: August 14 through November 9, 1995

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<u>ATTACHMENTS</u>:

EXECUTIVE SUMMARY

This inspection was performed using Inspection Procedure 93801, "Safety System Functional Inspection." The primary objective of this inspection was to assess the operational performance capability of safety-related steam turbine-drivers, which were supplied by the Terry Corporation. This initiative was prompted by recurring failures of safety-related steam turbine-driven standby pumps at several facilities in Region IV. An in-depth engineering review was performed concurrently at several Region IV facilities to assess the scope of design, maintenance, and testing practices related to these safety-related steam turbine-drivers. Previously identified generic safety-significant findings were pursued at each facility. The inspection examined several aspects of applicable experience review processes to determine why similar failures continued to occur.

The inspection found a wide variation in system designs, which has reduced the effectiveness of NRC generic communications related to Terry turbines. Further, the inspection found that most facilities did not have a programmatic requirement to formally review NUREGs for applicability to their facility. As a result, many licensees had not evaluated NUREG 1275, Volume 10, "Operating Experience Feedback Report - Reliability of Safety-Related Steam Turbine-Driven Standby Pumps," to identify failure mechanisms and potential actions which could be taken to prevent the failures. In addition, many licensee personnel stated that the turbine vendor has not provided a good focus for emerging technical issues. The inspection also found that licensees were not consistently implementing vendor recommendations. While the Terry Turbine User's Group was attempting to work with the vendor to provide a nuclear focus for technical issues, these licensees indicated that the user's group cannot be relied upon to solely solve the problems, because they do not represent all licensees.

As a result, the inspection found that similar steam turbine failures and problems continued to occur. Most licensees did not rigorously address vulnerabilities until their equipment was directly affected. For example, the importance of condensate removal for operation of the steam turbine-driven safety-related standby pumps has not generally been understood fully until after experiencing a mechanical overspeed trip. Similarly, an industry-accepted root cause for corrosion-induced governor valve stem sticking has not been determined, even though approximately 18 failures of this type have been observed nationally. In addition, the inspection found that licensees were not consistently monitoring the governor valve stems for sticking or consistently replacing the stems with a material which was less susceptible to corrosion.

In general, the inspection found that licensees[1] did not maintain the reliability of safety-related steam turbine-driven standby pumps with the same

[1] Arkansas Nuclear One, Units 1 and 2 (ANO-1 and -2), Cooper Nuclear Station (CNS), Comanche Peak Steam Electric Station, Units 1 and 2 (CPSES-1 and -2), Diablo Canyon Power Plant, Units 1 and 2 (DCPP-1 and -2), Palo Verde Nuclear Generating Station, Units 1, 2, and 3 (PVNGS-1, -2, and -3), River Bend Station (RBS), San Onofre Nuclear Generating Station, Units 2 and 3 (SONGS-2 and -3), South Texas Project, Units 1 and 2 (STP-1 and -2), Waterford Steam Electric Station, Unit 3 (WAT-3), Washington Nuclear Power-2 (WNP-2), and Wolf Creek Nuclear Generating Station (WCNGS)

rigor as other safety-related equipment, such as the emergency diesel generators. For example: licensees had not fully tested the existing designs at pressurized water reactors to support extended operation under station blackout conditions; the system designs had not always included instrumentation or alarms for alerting the operators to steam-line drain failures, which could prevent the standby pumps from performing their safety function; and routine surveillance testing had not always detected degradation of the safety-related standby steam turbine-drivers.

Detailed Plant-Specific Results:

Maintenance

- Licensee personnel at eight units (ANO-2; CPSES-1 and -2; PVNGS-1, -2, -3; and STP-1 and -2) relied on vendor technical information to perform governor valve maintenance (e.g., maintenance practices for stem packing instructions, valve bonnet alignment pins and valve stroke/linkage adjustments) and found that the vendor manual did not always provide sufficient detail. The vendor representative stated that they had prepared the technical information for maintenance with the assumption that an experienced turbine professional would be onsite directing the maintenance activity. The vendor indicated that the licensee was responsible for procuring expert technical services if they did not have a turbine professional on staff (Sections 4.4.2 and 5.4).

- Licensee personnel at eight units (CNS; CPSES-1 and -2; DCPP-1 and -2; WAT-3; WNP-2; and WCNGS) had not established a preventive maintenance requirement to refurbish or replace the standby steam-turbine governors on a periodic basis. At the exit interview personnel from CPSES stated that they planned to establish a preventive maintenance program for governors (Section 4.6).

- The inspectors found that licensee personnel at two units (WAT-3; and WCNGS) had not established a periodic preventive maintenance program for steam traps. At the exit interview personnel from WAT-3 stated that they planned to establish a preventive maintenance program for steam traps. In addition, none of the licensees had established a preventive maintenance program for drains (Section 6.6).

- Personnel at four units (CPSES-1 and -2; and STP-1 and -2) removed their steam traps after experiencing condensate-induced mechanical overspeed trips caused by poor preventive maintenance programs. Personnel at PVNGS-1, -2, and -3 upgraded their preventive maintenance programs for their steam traps after experiencing condensate-induced mechanical overspeed trips (Section 6.6).

- Personnel at three units (CNS, RBS and WAT-3) did not filter their turbine and governor oil through a 5μ filter prior to adding to the system (Section 7.4).

Engineering

- As a result of the lack of uniformity in system design and system complexity, licensee engineers at eleven units (CPSES-1 and -2;, DCPP-1 and -2; PVNGS-1, -2 and -3; SONGS-2 and -3; WAT-3, and WNP-2) did not always correctly evaluate NRC information notices related to steam turbine-driven standby pumps (Section 3.1).

- While NUREGs (such as NUREG 1275, Volume 10) were sometimes routed for review, the inspectors did not identify any licensees that routinely documented experience review associated with NUREGs (Section 3.1).

- The inspectors determined that only one facility (ANO) was monitoring success-on-demand (including surveillance test results), which is an important indicator of turbine reliability, for comparison with the reliability estimates used in probabilistic risk assessments (Section 3.2).

- The inspectors found that the drain configurations at three units (ANO-2; and DCPP-1 and -2) were not consistent with the vendor recommendation to continuously drain the steam lines. In addition, the turbine casing steam trap at WAT-3 was designed to allow a small amount of water to stand in the turbine casing following a turbine run. This also conflicted with the vendor recommendation that drain lines remain open when the turbine is idle to prevent corrosion of internal parts (Section 3.3.1)

- The inspectors found that oils with vapor-phase inhibitors were used at nine units (CNS; DCPP-1 and 2; PVNGS-1, -2, and -3; RBS; and SONGS-2 and 3). Further, the inspectors noted high turbine standby temperatures at SONGS, which made them the most susceptible to problems associated with the out-gassing of the vapor-phase inhibitor (Section 3.3.3).

- Licensee personnel at several facilities stated they relied on the turbine vendor (Dresser-Rand, Terry-Turbodyne, a joint venture) to evaluate emerging technical issues from a nuclear perspective. However, the vendor provided recommendations from a commercial perspective and did not conservatively and promptly identify issues related to nuclear applications to all affected licensees (e.g., condensate removal, governor valve stem, and use of vapor-phase inhibitors in oil) (Section 3.3).

- Licensee personnel at three units (CNS; and DCPP-1 and -2) were not members of the Terry Turbine User's Group. A Terry Turbine User's Group officer estimated that, nationally, 30 percent of the utilities were not members (Section 3.4).

- Licensee personnel had not proceduralized the requirement for cold-start testing at four units (ANO-1 and -2; CNS; WAT-3). However, personnel at these facilities stated that they do test from the standby condition. Personnel at ANO record the turbine standby temperature prior to each run (Section 4.4.1).

- Licensee personnel had not performed any type of dynamic governor valve performance trending at three units (CNS, RBS, WAT-3). Although personnel at two units (RBS and WAT-3) had used manual valve manipulation to detect stem binding, as discussed in Information Notice 94-66, this testing was not predictive at STP (Section 4.4.2).

- The licensees had operated the safety-related steam turbine-driven standby pumps at only three units (PVNGS-1, -2, and -3) for an extended period of time in a configuration representative of a total loss-of-alternating current to the safety-related steam turbine-driven standby pump and supporting equipment (Section 4.5).

- Based on a review of the safety analysis reports, the inspectors found that licensee personnel at nine units (ANO-1 and -2; CPSES-1 and -2; SONGS-2 and -3; STP-1 and -2; and WCNGS) had not demonstrated, by testing, that the safety-related steam turbine-driven pumps were capable of running over the full range of steam inlet pressures (Section 4.5).

- Licensee personnel at two units (CNS and WCNGS) were using incorrect assumptions to determine whether, or not, they had the liquid-nitrided governor valve stems (Section 5.2).

- At the time of the exit, potentially suspect stems were installed at four units (PVNGS-1, -2, and -3; and WNP-2). Personnel at three units (PVNGS-1, -2 and 3) planned to replace the stems with a material which was less susceptible to corrosion. At the exit interview, personnel at WNP-2 stated that they planned to inspect the installed governor valve stem during the next outage (Section 5.2).

- Licensee personnel at the WCNGS had no plans to restrict the use of the corrosion susceptible spare governor valve stems, which were in stores (Section 5.2).

- The inspectors identified that periodic inspection and dynamic testing capability are important to demonstrate the long-term acceptability of the new stem materials (Section 5.3).

- The inspectors determined that the system designs for seven units (ANO-1 and -2; DCPP-1 and -2; and, PVNGS-1, -2, and -3) did not include any instrumentation or alarms to alert the operators to steam-line drain failures. In addition, only personnel from RBS and WNP-2 had installed alarms or high level indicators for the turbine or turbine exhaust side steam traps or condensate pots/drains. (Section 6.4).

- Licensee personnel, generally, did not recognize that steam-line drains had a safety function to remove condensate until after discussing a condensate induced overspeed trip with NRC personnel. Condensate removal is an important safety function because condensate accumulation upstream of the turbine governor valve will cause an overspeed trip to occur and prevent the standby pumps from performing their safety function (Section 6.5).

- The inspectors identified that none of the licensees had performed a 4-hour run of the safety-related steam turbine-driven standby pumps after changing the oil type. This was a concern because the vendor had stated that oil aeration was detected on some turbines during the initial 4-hour qualification run and that the affected turbines required modification prior to shipment to the licensees. The susceptibility to oil aeration varies with oil type (Section 7.3).

DETAILS

1 INTRODUCTION

Historically, there have been several occurrences throughout the industry of safety-related steam turbine-driven standby pumps failing to start, failing to continue to run after starting, and tripping to a "lockout" condition which required manual operator actions at the turbine to return the turbine-driven pump to an operable status. More recently, there have been three additional examples at two Region IV plants (South Texas Project (STP) and Comanche Peak Steam Electric Station (CPSES)) where turbine-driven pumps have not operated as designed. These continuing failures have raised concern because the safety-related steam turbine-driven auxiliary feedwater pump is normally the only source of core cooling for pressurized water reactors during a station blackout.

This inspection compared the programs that the licensees had implemented to assure the reliability of the safety-related steam turbine-driven standby pumps to the level of attention they have given to other risk-significant safety-related equipment, such as the emergency diesel generators. The inspection also reviewed specific industry-recurrent failure mechanisms for turbines which were initially provided by the Terry Corporation. These failures included governor system failure or loss-of-speed control margin, governor valve stem binding, excessive condensate and/or moisture accumulation, and lubrication and speed control problems associated with oils and hydraulic fluids. The inspection also included an evaluation of some overspeed trip device malfunctions.

This inspection specifically reviewed safety-related steam turbine-driven standby pump applications in the auxiliary feedwater (AFW) system or the emergency feedwater (EFW) system at 15 Region IV pressurized water reactors. The inspection also reviewed steam turbine-driven standby pump applications in the reactor core isolation cooling (RCIC) system at 3 boiling water reactors. The inspection did not review data associated with the high pressure coolant injection system turbines (also supplied by the Terry Corporation) at boiling water reactors because these steam turbines were significantly larger than the turbines used in the AFW, the EFW, and the RCIC systems. Fort Calhoun Station was not included in this review effort because it does not have a safety-related steam turbine-driven standby pump that was produced by the Terry Corporation. The Callaway Plant and Grand Gulf Nuclear Station were also not included in this review effort because they were not in Region IV at the time of the inspection. Therefore, the information presented in this inspection report involves 18 individual units in Region IV.

The inspection was conducted at eight sites. Information gained during recent NRC inspections at CPSES and STP was also included in this report. (Reference NRC Inspection Reports 50-445/95-13; 50-446/95-13 and 50-498/95-10; 50-499/95-10, respectively.) Personnel at CPSES, STP, RBS and WNP-2 were contacted by telephone during the inspection. An in-office review was performed of documentation supplied by personnel from all 18 units.

2 SYSTEM CONFIGURATIONS

The Terry Corporation supplied similar commercial-grade steam turbines for use in the AFW, EFW and the RCIC systems at 18 Region IV units. The Terry Corporation became the Terry Turbine Division of Ingersol-Rand, and is now Dresser-Rand, Terry-Turbodyne, a joint venture. The turbine vendor will be referred to as "Dresser" in this report. In addition, the Woodward Corporation supplied various commercial-grade mechanical and electronic governors, which are used to control turbine speed.

The inspectors found that each pressurized water reactor unit had a unique configuration for the layout of the steam supply piping for the AFW, EFW turbines. For example, some systems used the trip-and-throttle valve as the steam admission valve, while other systems used a separate steam admission valve. At some facilities, the steam isolation valve was located close to the turbine. At others, the steam isolation valve was located a long distance away. Steam traps and/or condensate drain pots, upstream of the steam admission valves, were included in some systems. The designs varied because these systems were designed by different architect engineers. The system configurations for the boiling water reactors were much more similar because they were designed by a single nuclear steam system supplier.

3 EXPERIENCE REVIEW

Region IV performed this inspection to evaluate the implementation of the licensees' experience review process and to determine the status of safety-related steam turbine-driven standby pumps with respect to selected industry-recurrent failure mechanisms. The licensees, industry organizations, vendors, and the NRC have performed several studies in an attempt to identify and correct the causes of turbine failures. NRC issued NUREG 1275, Volume 10, "Operating Experience Feedback Report - Reliability of Safety-Related Steam Turbine-Driven Standby Pumps," and the following information notices to discuss events related to safety-related steam turbine-driven standby pumps:

- Information Notice 86-14, "PWR Auxiliary Feedwater Pump Turbine Control Problems," dated March 10, 1986;
- Information Notice 86-14, Supplement 1, "Overspeed Trips of AFW, HPCI, and RCIC Turbines," dated December 17, 1986;
- Information Notice 86-14, Supplement 2, "Overspeed Trips of AFW, HPCI, and RCIC Turbines," dated August 26, 1991;
- Information Notice 88-09, "Reduced Reliability of Steam-Driven Auxiliary Feedwater Pumps Caused by Instability of Woodward PG-PL Type Governors," dated March 18, 1988;
- Information Notice 88-67, "PWR Auxiliary Feedwater Pump Turbine Overspeed Trip Failure," dated August 22, 1988;

- Information Notice 90-45, "Overspeed of the Turbine-Driven Auxiliary Feedwater Pumps and Overpressurization of the Associated Piping Systems," dated July 6, 1990;

- Information Notice 90-76, "Failure of Turbine of Overspeed Trip Mechanism Because of Inadequate Spring Tension," dated December 7, 1990;

- Information Notice 93-51, "Repetitive Overspeed Tripping of Turbine-Driven Auxiliary Feedwater Pumps," dated July 9, 1993;

- Information Notice 94-66, "Overspeed of Turbine-Driven Pumps Caused By Governor Valve Stem Binding," dated September 19, 1994;

- Information Notice 94-66, Supplement 1, "Overspeed of Turbine-Driven Pumps Caused by Binding in Stems of Governor Valves," dated June 16, 1995; and,

- Information Notice 94-84, "Air Entrainment in Terry Turbine Lubricating Oil System," dated December 2, 1994.

The inspectors reviewed these publications, vendor information, and Terry Turbine User's Group Newsletters to identify the actions licensee personnel could take to prevent the selected industry-recurrent failures. The inspectors reviewed previous NRC inspection reports, licensee maintenance documentation, and interviewed plant personnel to determine which actions licensee personnel had taken to provide assurance that their safety-related steam turbine-driven standby pump(s) would perform the intended safety function(s).

3.1 Licensee Use of NRC Generic Communications

During the inspection, the inspectors requested that each licensee provide copies of the documentation of their review of NRC Information Notices 94-66 and its supplement; 93-51; 86-14 and its supplements; and, NUREG 1275, Volume 10. The inspectors also sampled responses to some of the other Information Notices listed above.

As a result of this review, the inspectors found that licensee personnel do not routinely document experience reviews associated with NUREGs. The system engineers at some units (STP and Arkansas Nuclear One (ANO)) had participated in the industry review of the document prior to publication. While these personnel were very familiar with the content of NUREG 1275, Volume 10, they stated that, in some cases, NUREGs are routed for information at their facilities, but no formalized evaluation is required. One other system engineer (CPSES) had received the document without any type of action item associated with completion of the experience review. The system engineers at Cooper Nuclear Station (CNS) and Waterford Steam Electric Generating Station, Unit 3 (WAT-3), were unaware that the document existed prior to this inspection.

The inspectors found that personnel at several facilities (Diablo Canyon Power Plant (DCPP); Palo Verde Nuclear Generating Station (PVNGS); San Onofre

Nuclear Generating Station (SONGS); and, WAT-3) incorrectly stated that NRC Information Notice 88-09, "Reduced Reliability of Steam-Driven Auxiliary Feedwater Pumps Caused by Instability of Woodward PG-PL Type Governors," was not applicable to their facility because they did not have a PG-PL-type governor. The information notice discussed the misapplication of buffer springs internal to the governor and subsequent speed instabilities. The inspectors noted that this failure could also occur in the EG-R-type actuators and in the PG-A-type governors, which were installed at these facilities. This was explained in NUREG 1275, Volume 10, but generally overlooked by licensee personnel. (Reference Table 3, "Governor Systems," for site-specific information.) The inspectors concluded that personnel performing experience reviews at these facilities did not understand the internals of the governors sufficiently to draw correct conclusions regarding the applicability of the information notice.

Similarly, the inspectors found that personnel at Washington Nuclear Project-2 (WNP-2) had performed a review of Information Notice 86-14, Supplement 2, and incorrectly concluded that an inspection of the governor sump was not necessary because the turbine oil was found to be clean. The information notice pointed out that the problems which had occurred at ANO were not detected by sampling the turbine oil every month and changing the lube oil filter every 6 months. The design of the EG-R-type actuator sump is such that changing the turbine oil will not change the oil in the actuator sump. Therefore, the sump is more subject to long-term accumulation of contaminants and should be inspected separately.

The inspectors also noted that the CPSES personnel performed a review of Information Notice 93-51, "Repetitive Overspeed Tripping of Turbine-Driven Auxiliary Feedwater Pumps," that discussed the importance of minimizing steam supply valve leakage based on failures which occurred at STP. The CPSES reviewer incorrectly determined, as discussed in NRC Inspection Report 50-445, 446/95-13, that the issue was not applicable to CPSES because of system design differences between the facilities. The licensee stated that the system design differences made it difficult to do an effective experience review for AFW issues.

The inspectors concluded that, as a result of the lack of uniformity and the complexity of the equipment, licensee personnel were not always correctly evaluating NRC information notices. Careful analysis of problems associated with safety-related steam turbine-driven standby pumps is necessary to determine the applicability of experience review.

3.2 Use of Licensee Experience

In NUREG-1275, Volume 10, the NRC reported that the industry-wide demand probability of failure for the turbine-driven auxiliary feedwater pump was 6.5E-2 (excluding maintenance unavailability), as compared with a value for the Surry Probabilistic Risk Assessment in NUREG-1150 of 1.1E-2 for auxiliary feedwater. These failures were primarily caused by overspeed trips. The inspectors interviewed licensee personnel to determine the availability of plant-specific failure data at each facility and to determine the consistency of the data with the individual plant examination submittals. The inspectors found a wide variation in the availability of failure data. In most cases, licensee personnel had not systematically established methods for tracking these failures. Most of the other licensees had access to recent failure history in some form, but they had not put the information in the context of total demands to develop a reliability estimate. Several utilities were tracking total availability, rather than success-on-demand.

Engineers at one facility (ANO) had completed a preliminary engineering analysis of the reliability data for the turbine-driven EFW pumps in preparation for implementation of the maintenance rule. The inspectors noted that the plant-specific failure data used in the utilities individual plant examination submittal was an order of magnitude less conservative than the results of the recent engineering analysis. Licensee personnel stated that the base probabilistic risk assessment model had not been updated with this new data. The licensee did plan to update the model as more reliability data, which was being developed for the maintenance rule, becomes available. The licensee was monitoring the effects of turbine reliability changes on core damage frequency on a monthly basis using a simpler model to approximate core damage frequencies. Licensee personnel stated that this information was being used to develop operating and maintenance strategies. Licensee personnel stated that for, ANO-2, the loss of the turbine-driven EFW pump was more important than the loss of one diesel generator. The reverse was true for ANO-1.

Conditional Probability that Turbine Driven EFW Pump Will Be Available, Start and Run for a Valid Demand Signal			
UNIT	PROBABILITY	TIME PERIOD	SOURCE OF INFORMATION
ANO-1	90 - 95%	1989 - 1994	EFW System Conditional Probability Analysis 5/26/94
ANO-2	87 - 93%	1989 - 1994	EFW System Conditional Probability Analysis 5/26/94

Individual Plant Examination Data for Turbine-Driven EFW Pump				
UNIT	FAILURE MODE	MEAN	ERROR FACTOR	TIME PERIOD
ANO-1	Fail to Start	5.76E-3	5.21	Pre - 1990
	Fail to Run	9.37E-5	1.81	
	Maintenance	3.11E-4	1.28	
ANO-2	Fail to Start	7.27E-3	5.21	Pre - 1990
	Fail to Run	6.45E-3	9.62	
	Maintenance	2.91E-4	1.81	

As stated in NUREG 1275, Volume 10, most of the failures which have occurred for standby steam turbine-drivers are related to the start sequence. The inspectors concluded that success-on-demand (including surveillance test results) was an important indicator of turbine reliability, and that most licensees were not monitoring this data for comparison with the reliability estimates used in probabilistic risk assessments.

3.3 Vendor Experience

As discussed above, most safety-related auxiliary feedwater and RCIC system standby steam turbine-drivers were supplied by Dresser as commercial-grade items. Dresser did not perform the original design of the steam supply, the steam exhaust, or the condensate removal systems. Licensee engineers have typically accepted full-design responsibility for these systems from the original architect engineers or the nuclear steam system supplier. However, licensee engineers typically lack specialized turbine expertise.

The inspectors evaluated the design interface between the licensee and the turbine vendor for three emerging technical issues: mechanical overspeed tripping due to inadequate condensate removal; mechanical overspeed tripping due to corrosion of governor valve stems; and, use of vapor-phase inhibitors in oil. This inspection was performed to assess the effectiveness of the vendor/licensee interface with respect to assuring reliable turbine operation.

3.3.1 Condensate Removal

The inspectors reviewed nine vendor technical manuals for Terry turbines. The inspectors found that six of the nine technical manuals (ANO-2, CPSES, DCPP, STP, PVNGS, and WAT-3) contained recommendations for condensate removal. In Section 10, "Operation," of these technical manuals, under the paragraph titled, "Emergency or Quick Start-up," the vendor stated, in a note that, "[i]f emergency quick starts are anticipated provision should be made for steam lines to be continuously drained . . . ." The inspectors also noted that the three remaining technical manuals (ANO-1, SONGS, and Wolf Creek Nuclear Generating Station (WCNGS)) did not include this statement.

The inspectors discussed the inconsistency in the recommendation with the vendor representative. He stated that the turbine was designed to run with very low quality steam. However, provisions should be made for steam lines to be continuously drained at any installation which anticipates emergency quick starts. He stated that the drains should ensure that condensate does not accumulate upstream of the governor valve, since this could lead to an overspeed trip during starting. He also stated that Dresser would evaluate the need for updating the remaining technical manuals. The inspectors evaluated the drain configuration at the applicable units and only found three units which did not comply with the vendor recommendation to continuously drain the steam lines (ANO-2; and DCPP-1 and -2).

At ANO-2, the safety-related steam turbine-driven standby pump turbine casing drain valves were normally closed. The operators opened the valves once per shift to drain any accumulated water out of the turbine. The licensee used a test to demonstrate that this operator monitoring approach was sufficient to ensure that condensate did not accumulate upstream of the governor valve. The licensee ran the turbine during a period when the steam isolation valves were leaking significantly. Without opening the turbine casing valves, licensee personnel secured the turbine, waited 17 hours, and then successfully restarted the turbine. Licensee personnel also stated that maintenance was performed to reduce the steam isolation valve leakage. The inspectors noted that this approach depended on continued operability of the nearby steam traps. The licensee stated that operators routinely monitored trap performance once per shift.

At DCPP, the turbine casing drain valves on each unit's safety-related standby steam turbine were also normally closed. The licensee stated that if the steam admission valves leaked, then the turbine casing drains would be opened every 4 hours. Cold quick-starts were performed at DCPP once per quarter and prewarmed starts were performed twice per quarter. If the turbine was started for warm start testing, operators opened the drain valves for approximately 1 minute, while warming the steam lines and turbine, to remove any moisture. The cold quick-start tests simulated an automatic turbine start (i.e., the drains remained closed).

In Section 3 of most of the technical manuals for the Terry steam turbines, under the paragraph titled, "Auxiliary Piping," the vendor stated that, "drain lines are to be open when the turbine is idle to prevent accumulation of condensate in the turbine, which will result in corrosion and rapid deterioration of internal parts." The inspectors noted that the turbine casing steam trap at WAT-3 was designed to allow a small amount of water to stand in the turbine casing following a turbine run.

The inspectors found that the system configurations at four units were not in accordance with the vendor recommendations, which were provided to the licensees. The personnel at both DCPP and ANO-2 were attempting to meet the intent of the vendor's recommendations with respect to condensate accumulation by use of operator monitoring. The inspectors concluded that operator monitoring at DCPP and ANO-2 was critical. Otherwise, these turbines were more vulnerable to excessive condensate accumulation because the turbine casing drains were closed. At the exit interview, personnel at WAT-3 stated that they planned to evaluate the need for modifying their drain system to ensure water would not stand in the turbine casing following a turbine run.

3.3.2 Governor Valve Stem Corrosion

In Region IV, four units (ANO-2, STP-2, CPSES-1, and River Bend Station (RBS)) have experienced overspeed trips, which were caused by corroded valve stems. At least 18 such events have occurred nationally. The inspectors found that stems, which had been manufactured with a liquid-nitride surface treatment, were present in each of the failures associated with governor valve stem sticking. The inspectors reviewed vendor recommendations related to this issue to determine if they adequately characterized the risk associated with the use of the valve stems manufactured with a liquid-nitride surface treatment.

At the time of the inspection, Dresser had not recalled the suspect stem material for nuclear applications because they believed it was suitable, provided the licensee could control moisture and steam chemistry. In a March 24, 1993, letter to Surry Nuclear Power Station (with copies to other facilities) Dresser discussed the vulnerability of some 410 stainless steel governor valve stems to corrosion in the presence of moisture and corrosive steam chemistry.

Licensee personnel at two units (STP-2 and CPSES-1) stated that, prior to the overspeed trips at their facility, they had discussed the potential vulnerability with Dresser. System engineers stated that when they contacted Dresser directly about the valve stem corrosion issue, the Dresser representative stated that over 100 of the stems were in service with only a few failures. Thus, system engineers at STP and CPSES incorrectly concluded that the possibility of failure at their unit(s) was remote. (Reference Table 3, "Governor Systems," attached, for site-specific information.)

Both licensees believed that gross leakage was necessary for the corrosion phenomena to occur. In the STP-2 design, the steam isolation boundary was close to the turbine; however, the steam isolation boundary valve did not leak measurably at the time of the overspeed trip. The steam isolation boundary at CPSES-1 was further from the turbine and the leakage was approximately 13.75 Lph [3.5 gph]. The inspectors reviewed steam supply valve leakage controls at all of the facilities and determined that the amount of moisture necessary for valve stem corrosion could be intermittently present at most units.

At the request of industry personnel, Dresser is currently performing qualification testing to develop a replacement valve stem, which is more corrosion resistant.

3.3.3 Use of Vapor-Phase Inhibitors in Oil

On April 21, 1978, the NRC issued IE Circular 78-02, "Proper Lubricating Oils for Terry Turbines." This circular reiterated the vendor recommendation to use turbine lubricating oil with vapor-phase corrosion inhibitors, such as Mobil Vaprotec Light, to prevent internal corrosion of turbine parts. Vapor-phase inhibitors out-gas from the oil onto all surfaces to form a protective barrier. At temperatures above 48.9°C [120°F], the vapor-phase corrosion inhibitor in Mobil Vaprotec Light oil out-gases and plates out on any surface, forming a sticky, varnish-like substance. If the oil with vapor-phase inhibitors is also used in the governor system, speed control problems can result. The formation of a sticky, varnish-like substance can interfere with the proper operation of the overspeed trip tappet. The tappet can bind, preventing an overspeed trip or making resetting the turbine difficult.

On August 26, 1991, the NRC issued Information Notice 86-14, Supplement 2, "Overspeed Trips of AFW, HPCI, and RCIC Turbines," to address overspeed tripping due to fouled control oil. The information notice did not refer to the use of Mobil Vaprotec as a potential cause of the failure at ANO-2 because there was not enough industry data at that time to support this conclusion.

The May 1994 Terry Turbine User's Group letter, however, stated that the following plants have had oil problems with Mobil Vaprotec Light: ANO -1 and -2; WAT-3; STP-1 and -2; Clinton Power Station, Unit 1; LaSalle County Nuclear Power Station, Units 1 and 2; Pilgrim Nuclear Power Station Unit 1; and, St. Lucie Plant, Units 1 and 2.

In 1993, Dresser reviewed an industry consultant report that indicated about half of the utilities, which used vapor-phase inhibitor oils, were experiencing problems. In a September 21, 1993, letter to the Electric Power Research Institute/Nuclear Maintenance Applications Center, Dresser acknowledged the problem of solids forming in vapor-phase oil as a result of high standby temperatures. They stated that their turbine was never designed for standby temperatures between approximately 49-93°C [120-200°F]. Dresser further stated that, if it was not reasonable for the owners to maintain lower standby temperatures by maintaining the steam supply valves free of leaks, then conversion to a high-grade turbine oil should be considered as an alternative to the solid forming problems associated with high oil temperatures.

The inspectors found that oils with vapor-phase inhibitors were used at nine of the 18 units (CNS [Mobil Vaprotec Light]; DCPP-1 and -2 [Shell VSI-68]; PVNGS-1, -2, and -3 [Shell VSI-32]; RBS [Mobil Vaprotec Light]; and, SONGS-2 and -3 [Mobil Vaprotec Light]). The inspectors also found elevated standby temperatures at 2 of these units (SONGS-2 and -3). The inspectors determined that the SONGS units were currently the most susceptible to problems associated with the out-gassing of the vapor-phase inhibitor.

The inspectors noted that standby temperature was directly related to steam isolation valve leakage. Most licensees did not routinely measure either standby temperature or steam supply valve leakage. If steam supply valve leakage increases in the remaining units that use vapor-phase inhibitors, they may also experience the solid forming problems.

The inspectors discussed the issue with the vendor representative. He stated that the Dresser recommendations for use of turbine oil were intended to provide flexibility to the licensee. The recommendations allow the licensee to select the correct turbine oil, depending on plant-specific conditions. The inspectors asked if the switch to high grade turbine oils had resulted in any new failures. The vendor representative was not aware of any.

Based on interviews with licensee personnel, the inspectors found that licensee personnel lacked turbine expertise. They relied on the turbine vendor to evaluate emerging technical issues from a nuclear perspective. However, the vendor lacked detailed system installation information and, as a result, provided recommendations from a commercial perspective (i.e., restating the equipment limitations without making conservative recommendations for nuclear applications). Licensee personnel also stated that the vendor did not routinely provide updated vendor information to all licensees when a new issue was identified. The inspectors also found that licensees did not consistently implement vendor recommendations.

3.4 Terry Turbine User's Group

During the summer of 1993, licensee personnel from ANO-2, STP, and other facilities worked with the Nuclear Maintenance Applications Center, which is operated by the Electric Power Research Institute, to establish the Terry Turbine User's Group. The Terry Turbine User's Group initiated several programs to improve standby turbine reliability. On an intermittent basis they publish a newsletter, which addresses ongoing technical concerns. As discussed above, a May 1994 Terry Turbine User's Group newsletter thoroughly addressed the use of vapor-phase inhibitors in Terry turbines.

The Terry Turbine User's Group sponsored two maintenance workshops to provide hands-on training covering governors, trip-and-throttle valves, overspeed trip devices, and the turbine itself. Through the Nuclear Maintenance Applications Center, operated by the Electric Power Research Institute, the Terry Turbine User's Group produced the "NMAC Terry Turbine Controls Maintenance Guide (NP-6909)." In many cases, this manual provided specific quantitative guidance (e.g., clearances related to governor valve stem linkage assembly) and measurements (e.g., appropriate spring tension for the emergency trip spring). A companion troubleshooting and performance monitoring guide is being developed. The inspectors determined that this group was effectively addressing technical issues and were providing a useful forum for the dissemination of technical information regarding the use of Terry turbines.

The inspectors found that all licensees were not represented in the Terry Turbine User's Group. Licensee personnel at three units (CNS and DCPP-1 and -2) in Region IV were not members of the Terry Turbine User's Group. A Terry Turbine User's Group officer estimated, that nationally, 30 percent of the utilities were not members. Licensee personnel explained that the current-rate structure for joining the Electric Power Research Institute is based on total megawatts produced. As a result, utilities with a heavy total investment in fossil and hydro-electric plants were less likely to join the Electric Power Research Institute and were ineligible to become members of the Terry Turbine User's Group. The inspectors were told that the Electric Power Research Institute was working to change the rate structure for nuclear activities so that all nuclear facilities will be charged a comparable fee, making the information equally accessible. The inspectors noted that the licensee representatives were usually working level personnel (system engineers, maintenance engineers), not licensee management, and were not positioned to direct changes at their unit(s). The inspectors determined that it was not appropriate to rely too heavily on this organization to resolve safety issues.

4 GOVERNOR SYSTEMS

4.1 Background

Earlier NRC and industry studies had shown that the most significant factors in the failures of safety-related steam turbine-driven standby pumps had been the failures of the turbine drivers and their controls. The governor system of these turbines had played a large role in the failures of the turbines to start or to keep running. In particular, a correct governor response is critical to prevent mechanical overspeed trips of the steam turbines during the start (or restart) sequence. The majority of standby turbine failures were the result of malfunctions of the turbine governor during cold quick-starts. Overall, system dynamic problems must be fully considered to prevent malfunctions. The inspectors found that several contributing factors often combine to cause mechanical overspeed trips.

4.2 Governor System Designs

The governor system consists of the governor, the governor controls, the governor valve, and the linkage connecting the governor to the governor valve. In standby, steam is isolated from the turbine. Governor valves usually go full open when the turbine is secured, and remain full open in the standby condition. In general, the turbine controls were designed so that a safety signal, such as an engineered safety feature actuation, opens a steam supply to the turbine. Turbine rotation was necessary to develop the hydraulic pressure used to move the governor valve. After turbine speed increases, the governor acts to throttle close the governor valve and take control of turbine speed at a preset minimum speed. Then the governor will ramp open the governor valve at some predetermined rate until the turbine reaches full speed.

4.3 Timing Issues

The inspectors found that the timing of the start sequence of steam turbine-driven standby pumps was critical. The turbine controls must be designed to coordinate the opening of the steam supply valve(s) with the throttling of the governor valve. The governor valve must throttle closed before the steam supply valve(s) fully open to prevent a mechanical overspeed trip of the turbine. The design of the timing sequence was also influenced by the design of the steam supply piping. Condensate formed when the steam isolation valves open and steam passed through the cold-steam supply piping. More condensate formed at units which have remotely located steam supply valves (as much as 75 m [250 ft] away from the turbine).

The vendor stated that Terry turbines were designed to run reliably with very low-quality steam, but they were not designed to start (or restart) with excessive condensate. The vendor stated that excessive condensate accumulation could increase the likelihood of an overspeed trip for a number of different reasons. Much of the condensate that passed through the turbine flashed to steam, resulting in erratic turbine speed changes. The design of the governor system was not responsive enough to control the speed changes caused by the water steam mixture; therefore, the turbines could trip on mechanical overspeed. The governor valves were also designed for a steam application and not for closing against water.

Licensee personnel from several units reported extensive testing and modifications during the initial licensing phase to address this design vulnerability. Licensee personnel developed a variety of timing strategies. For example, four units' design (ANO-2; and PVNGS-1, -2 and -3) incorporated automatic warm-up valves into the start sequence so that condensate would slowly be introduced to the turbine. Two units' design (CPSES-1 and -2) opened the steam supply valves quickly in an attempt to sweep the condensate through the turbine before the governor system developed enough hydraulic pressure to control speed. With either strategy, turbine reliability was very sensitive to changes in governor valve/steam supply valve/bypass valve coordination and to changes in the amount of condensate.

4.4 Periodic Testing

The inspectors reviewed licensee surveillance tests to determine if the licensee engineers had developed effective, periodic testing programs which would detect: (1) changes in governor valve/steam supply valve/bypass valve coordination; (2) changes in the amount of condensate which initially passes through the turbine; or, (3) the onset of governor valve linkage/stem binding. The inspectors found that, in all cases, the Technical Specifications required the licensees to perform periodic pump flow tests; however, these tests were not always written to confirm the readiness of the safety-related standby steam turbine-drivers.

4.4.1 Standby (Cold Quick-Start) Turbine Test Requirements

The inspectors noted that periodic testing must duplicate actual demand actuation conditions to adequately demonstrate the operational readiness of the turbine-drivers. The test should be performed in the standby condition (i.e., without preconditioning the system by prewarming or draining the steam lines). This type of testing had historically been referred to as cold quick-start testing or cold-start testing. However, the inspectors noted that some licensee personnel maintained their turbine and steam lines in a prewarmed condition to minimize condensate formation during turbine starts. Licensee personnel from every unit stated that it was their normal practice to perform testing to demonstrate standby readiness.

Some licensee personnel (DCPP-1 and -2) did not perform a standby start for every test. Some of the time they prewarmed and drained the turbine to mitigate aging effects. The inspectors reviewed the licensees' surveillance test procedures and found that licensee personnel had not proceduralized the requirement for periodically testing without preconditioning at four units (ANO-1 and -2; Cooper Nuclear Station (CNS); and WAT-3). At DCPP-1 and -2, cold quick-starts were performed once per quarter and prewarmed starts performed twice per quarter. At STP-1 and -2, cold quick-starts were performed following maintenance. Personnel at STP determined that 80 to 90 percent of the cooldown occurs within the first 2 hours after a run. They routinely perform all surveillances at least 2 hours after a previous run. Personnel at ANO-1 and -2, had included a requirement to measure turbine inlet temperatures prior to a run, but the procedures did not specifically include precautions to prevent preconditioning. As stated in Section 3.3.1, the operators at ANO-2 open the valves once per shift to drain any accumulated water out of the turbine. ANO-1 and -2 does not link the operator action to drain the lines with the monthly surveillance test. Operators may drain the lines before or after the turbine run. (Reference Table 1, "Turbine Surveillance Requirements," attached, for site-specific information.)

Since the majority of standby turbine failures were the result of malfunctions of the turbine governor during cold quick-starts, the inspectors concluded that the failure to specifically require periodic standby testing (i.e., without warming or preconditioning) was a minor program weakness.

4.4.2 Governor System, Governor Valve, and Steam Supply Valve Performance Trending

The inspectors noted that Dresser recommends that governor valve coordination be verified quarterly. The inspectors verified that each unit operated the standby turbines at least quarterly. This testing provided a baseline assurance that the standby turbines were operable, but it did not detect loss-of-reliability margin.

The inspectors found that those licensees that had trended speed trace data were best able to confirm governor valve/steam supply valve/bypass valve coordination. Licensee personnel were able to use speed trace data to identify potential governor valve binding issues, timing sequence changes, and changes in the quantity of condensate formed during the start sequence. For example, the system engineer at ANO-2 used speed trace data to identify a slight governor valve alignment problem, thus, avoiding a failure of the governor valve. The alignment problem occurred during a governor valve bonnet replacement. Licensee personnel at ANO-2 incorrectly assembled the valve and did not install required valve alignment pins. The replacement bonnet had not come drilled to accept the required alignment pins and the vendor drawing did not show that the holes needed to be drilled.

The inspectors discussed the lack of detailed information with the vendor representative. The vendor representative stated that they prepared the technical information assuming that an experienced turbine professional would be onsite directing the maintenance activity. He further stated, it was the responsibility of the licensee to procure that expertise if they did not have a turbine expert in-house. The inspectors determined that the vendor interface was ineffective in this case.

The inspectors noted that speed trace data for the STP-2 turbine indicated speed control anomalies prior to the December 19, 1994, mechanical overspeed trip. Personnel at 11 units (ANO-1, and -2; PVNGS-1, -2, and -3; SONGS-2, and -3; STP-1, and -2; WNP-2; and WCNGS) were trending speed trace data. The engineers at 2 other units (CPSES-1 and -2) were monitoring governor valve performance during the start sequence using strain gauge data and valve position data. The engineers at 2 units (DCPP-1 and -2) used pump discharge pressure for trending governor valve performance. The inspectors noted that system conditions have to be duplicated during every test for a known relationship to exist between speed and flow.

The inspectors found that the engineers at three units (CNS, WAT-3, and RBS) were not performing any type of dynamic monitoring. The system engineers stated that they did not have the equipment to perform meaningful dynamic monitoring of governor/governor valve performance. The inspectors were concerned with this situation because a recent Terry Turbine User's Group Newsletter noted that slow degradation of governor systems is difficult to diagnose without transient monitoring and recording equipment or a thorough performance monitoring program.

The inspectors determined that licensee personnel at WAT-3 and RBS had relied on successful pump starts to validate the valve coordination and manual governor valve manipulation necessary to prevent binding problems. However, the inspectors noted that manual valve manipulation was **not** capable of predicting governor valve stem binding at STP. Personnel at CNS had stopped the manual valve manipulation in mid-May 1995; since then, they had relied solely on their routine flow test. The inspectors were concerned that these units did not have an optimal method for identifying governor system weaknesses prior to failure. (Reference Table 3, "Governor Systems," attached, for site-specific information.)

4.5 System Design Verification Testing

As stated in NUREG-1275, Volume 10, some governor instabilities are only exhibited during stand-alone operations. Based on interviews with licensee personnel, the inspectors found that personnel at only three units (PVNGS-1, -2, and -3) had performed an extended stand-alone turbine run in conjunction with a total loss of alternating current. (Reference Table 2, "Turbine Design Verification Tests," attached, for site-specific data.)

The inspectors noted that NUREG 1154, "Loss of Main and Auxiliary Feedwater Event at the Davis-Besse Plant on June 9, 1985," discussed the importance of testing all design bases steam-line configurations. The inspectors reviewed the safety analysis report for each unit and found a wide variation in the design verification testing requirements. Although some units had tested the steam supply configurations over the full range of steam inlet pressures, not all units had incorporated this verification. Personnel at some units performed endurance tests followed by a restart test and at some units personnel demonstrated only the capability of the pump to produce rated flow at normal operating temperatures and pressures. (Reference Table 2, "Turbine Design Verification Tests," attached, for site-specific data.)

The inspectors found that licensee personnel at nine units (ANO-1 and -2; CPSES-1 and -2; SONGS-2 and -3; STP-1 and -2; and WCNGS) had not demonstrated, by testing, that the safety-related steam turbine-driven pumps were capable of running over the full range of steam inlet pressures. Personnel at STP had tested over part of the steam inlet pressure range. They had tested the turbines as low as 400 psig, however, steam inlet pressure was expected to go as low as 100 psig. The inspectors were also not able to establish that restart capability was fully verified by test. However, the inspectors did not review the associated preoperational and hot functional test data packages. In some cases, more testing than was clearly described in their safety analysis report may have been performed.

The capability to restart can be important. As an example, NRC documented in Information Notice 86-14 that three steam turbine-driven standby pumps started following a reactor trip at the Turkey Point plant. The operators secured the turbines when they were no longer needed. When the turbines subsequently received another auto-start signal, all three turbines tripped on overspeed.

While licensee personnel believed this event occurred because the governors were inadequately reset, the event highlights the importance of demonstrating the restart function.

The inspectors noted that auxiliary feedwater standby turbines are frequently secured by the operators after steam generator levels stabilize, because it is easier for the operators to control steam generator levels with motor-driven pumps. The inspectors also noted that emergency operating instructions at pressurized water reactors typically do not include precautions to not secure the turbine-driven auxiliary feedwater pumps until after decay heat is reduced enough to allow time for the operator to manually restart the turbine. Also, boiling water reactor designs include automatic reactor water level controls that stop and start the turbine-drivers used in the RCIC system. Therefore, it is important in both pressurized water reactor designs and boiling water reactor designs that condensate removal be functional after the turbine is secured so that the water will drain out.

4.6 Governor Preventive Maintenance Practices

In NUREG-1275, Volume 10, the NRC reported that several governor problems had been traced to inadequate maintenance. As a result of this inspection, the inspectors noted that licensee personnel at eight units (CNS; CPSES-1 and -2; DCPP-1 and -2; WAT-3; WNP-2; and WCNGS) had not established periodic maintenance requirements for the turbine governors. At the exit interview, personnel from CPSES stated that they planned to establish a preventive maintenance program for governors. Personnel from WAT-3 stated that they had replaced their governor in May 1994 due to vapor-phase inhibitor buildup. The engineers at the remaining units planned to ship the governor to the manufacturer for refurbishment or planned to replace the governor on a specified frequency. The majority of these licensees specified a frequency of 5 years or every third refueling outage for this preventive maintenance task. (Reference Table 3, "Governor Systems," attached, for site-specific information.)

4.7 Governor Modification Control

In NUREG-1275, Volume 10, the NRC reported that several governor problems had been traced to inadequate modification control between the various vendors (Woodward and Dresser) and the utilities. The inspectors interviewed licensee personnel and determined that Woodward's controls for tracking the governor design configuration at each unit had been adequately implemented. Licensee personnel stated that the nameplates of recently purchased components were marked with a "9903-" prefix, which indicated that configuration control would be monitored by the vendor. The nameplates of components that had been modified in the field by Woodward were marked with a "US" beginning in 1993. This marking indicated that the field configuration would not match the documentation at Woodward. When the component was returned to Woodward for refurbishment the documentation was updated and the "US" was removed from the nameplate.

The inspectors verified that several specific upgrades had been implemented at the units. The inspectors verified that all units, which used an electronic governor, had installed Terry Design Improvement 6. This modification added an oil sump for the EG-R-type actuator of an EG-M type governor control box to improve governor control for quick-starts. The inspectors also noted that all remote speed control bellows for mechanical governors were vented to prevent speed changes with changes in ambient temperature as discussed on page A-1 of NUREG-1275, Volume 10. Licensee personnel verified that external wiring for electronic governor EG-M-type control boxes and EG-R-type actuators was sized and shielded as specified by Woodward. The licensees also verified that the direct current power supply for electronic governors was connected to the battery as specified by Woodward. All governor control systems had a speed ramp provision to minimize overspeed during quick-starts. In addition, all licensee personnel had upgraded to the latest overspeed tappet design.

5 GOVERNOR VALVES

5.1 Background

As discussed in Section 3.3.2, failures of the turbine-drivers caused by corrosion-induced governor valve stem binding occurred at four units (ANO-2, CPSES-1, RBS, and STP-2) in Region IV. Similar events have occurred at approximately 18 sites throughout the country. On June 16, 1995, the NRC issued Supplement 1 to NRC Information Notice 94-66, "Overspeed of Turbine-Driven Pumps Caused by Binding in Stems of Governor Valves," to provide additional information to licensees regarding these failures.

Based on metallurgical examinations, licensee personnel at some Region IV units have determined that a 1976 change in valve stem material processing (i.e., from gaseous to liquid-nitride surface treatment), in conjunction with conditions conducive to corrosion, leads to rapid stem failure. However, an industry-accepted root cause for governor valve stem sticking had not been formally determined at the time of the inspection.

5.2 Stem Materials

Licensee personnel at each site, that had experienced the stem failure, had replaced the corrosion susceptible governor valve stem material (usually a liquid-nitride surface treatment) with a more corrosion resistant material. Entergy Operations, Inc., management also studied their other units including WAT-3. They identified that the governor valve stem in place at WAT-3 had the liquid-nitride surface treatment. Personnel at WAT-3 installed a more corrosion resistant stem during the inspection. The only other units that had the stems upgraded to a material less susceptible to corrosion, without having experienced a failure, were SONGS-1 and -2.

The inspectors found that older valve stems, which most licensee personnel believed to be manufactured using the gas-nitride surface treatment process, tend to corrode slowly via pitting. As an exception, based on a metallurgical examination, personnel at CPSES believed their older stem was manufactured using a liquid-nitride surface treatment process. When visually inspected, the inspectors observed that the older stems had a uniform black coating with some pitting.

Region IV licensees determined that the valve stems that had recently failed were manufactured with the liquid-nitride surface treatment process. Licensee personnel noted the failed stems appeared to rapidly corrode via a general corrosion mechanism or possibly galvanic corrosion. Some licensee personnel attributed the failures to increased sulfur levels in the carbon spacers. The inspectors observed that the failed liquid-nitride surface treated stems had striped black corrosion marks that paralleled the position of the carbon spacers and stainless steel washers. The liquid-nitride surface-treated stems also had brown porous corrosion products in the area of the valve stem leak off. The inspectors found that while industry personnel had not reached agreement regarding the precise cause of the corrosion, the corrosion occurred on recently replaced valve stems manufactured with the liquid-nitride surface treatment.

Personnel at four units (CNS; DCPP-1 and -2; and WCNGS) believed that the stems they currently had in use had the gas-nitride surface treatment. Dresser personnel stated that a change in the surface treatment process was first allowed in 1976. Licensee personnel at DCPP and CNS determined that the valve stems installed in their units were manufactured before 1976. The licensee for WCNGS believed that a gas-nitrided stem was installed because they had not replaced the original stem. However, the vendor representative stated that this was not sufficient basis because some of the turbines were originally shipped with liquid-nitride surface treated stems installed. CNS personnel had also evaluated that a valve stem that was stored in the warehouse was acceptable because it was manufactured in 1980. After the inspectors discussed the vendor-supplied date with the CNS system engineer, he stated that he would evaluate this information before using the valve stem in stores.

The system engineer for CNS stated that the installed governor valve stem bound when the operators attempted to start the turbine after the previous refueling outage. CNS personnel believed that the stem binding occurred because the turbine sat idle for an extended period of time. They did not believe the binding was caused by corrosion. The CNS engineers determined that the old carbon spacers most likely had a low sulfur content; therefore, the valve stem was less susceptible to corrosion. The licensee also revised the operating procedure to improve moisture control in the valve stem leak-off region. The licensee had inspected the valve stem via the governor valve stem leak off and had not noted any signs of corrosion.

The inspectors were concerned that this method of inspection was not adequate, because it was not possible for the licensee to detect corrosion in the vicinity of the carbon spacers and stainless steel washers. The clearances between the carbon spacers/stainless steel washers and the valve stem were too tight to allow visual inspection without disassembly. After discussions with the inspector, CNS personnel agreed that the inspection of the valve stem was inadequate. As corrective action, they planned to perform a full inspection during the next refueling outage (November 1995) and to evaluate the need for replacing the valve stem at that time.

At four units (PVNGS-1, -2 and -3; and WNP-2), licensee personnel were not able to positively determine which type of valve stem material was installed.

They stated that Dresser personnel did not consider that the material processing change would affect the form, fit, or function of the stem and, as a result, Dresser personnel did not initially track stems manufactured by the two processes separately. The PVNGS personnel planned to replace the present stems in each unit with a more corrosion-resistant material during the next refueling outage for each unit.

The licensee for WNP-2 was the only licensee that believed that the stem material could have been susceptible to the corrosion process, but had no plans to evaluate the stem for replacement. At the exit, personnel from WNP-2 stated that they planned to inspect the governor valve stem during the next outage and make a replacement determination at that time.

The inspectors also noted that two spare valve stems in stores at WCNGS were believed to be of the susceptible material. However, WCNGS personnel had no plans to place any type of engineering hold on the use of the suspect stem material. (Reference Table 3, "Governor Systems," attached, for site-specific information.)

The inspectors concluded that licensee personnel were not consistently replacing the suspect governor valve stems with a material which was less susceptible to corrosion.

5.3 <u>Validation of New Stem Materials</u>

The inspectors found that a variety of different stem materials had been used to improve corrosion resistance, such as: Inconel 718; 410 stainless steel, coated with chromium nickel; 422 stainless steel, coated with aluminum nickel and ferralium.

Licensee personnel stated that no overspeed trips had occurred as the result of corrosion of valve stems made of the new materials. However, the new stem materials have not been in service very long. Engineers at the units with the new stem materials have a variety of inspection and test programs to determine the long-term acceptability of the new stem materials. Some licensee engineers were performing routine surveillance tests which were sensitive enough to detect the onset of binding. Other licensee engineers were inspecting the new stem material on a periodic basis to establish confidence that it is an appropriate material selection. The inspectors determined that periodic inspection and dynamic testing capability were important to demonstrate the acceptability of the new stem materials.

5.4 <u>Governor Valve Maintenance Practices</u>

The level of detail in governor valve maintenance instructions ranged from copying a page out of the vendor manual to step-by-step disassembly/reassembly instructions. The inspectors found that the vendor information provided to licensee personnel, related to the installation of governor valve stem packing, was not very detailed. The vendor typically supplied a drawing which indicated the general arrangement of the carbon spacers and stainless-steel washers. The drawing did not specify how many washers and spacers should be installed, nor did it specify the final acceptable clearance. The inspectors noted that missing spacers and washers can result in cocked spacers and washers and an associated increase in friction forces.

Licensee personnel at eight units (ANO-2; CPSES-1 and -2; PVNGS-1, -2, -3; and STP-1, and -2) relied on vendor technical information to perform governor valve maintenance (e.g., maintenance practices for stem packing instructions, valve-bonnet alignment pins, or valve stroke/linkage adjustments). These licensees found that the vendor technical information did not always provide sufficient detail for maintenance to be successful. After maintenance errors related to the installation of the governor valve stem packing occurred at these facilities, licensee personnel upgraded their governor valve assembly instructions. Personnel at these units developed more detailed instructions, which included clearance specifications and counting the number of washers and spacers installed in the packing assembly. Licensee personnel stated that the vendor had provided subjective information for adjusting the linkages. As stated above, the Terry Turbine User's Group had developed guidance documents to provide clarifying information, but this guidance had not been implemented at every facility. The inspectors concluded that the information in the vendor manual did not provide sufficient guidance for licensees to reliably perform maintenance on the governor valve.

6 CONDENSATE CONTROLS

6.1 Background

As discussed in Section 4, Terry turbines were designed to run reliably with very low-quality steam. The turbines were not designed to start (or restart) with excessive condensate in the turbine. As a result, multiple mechanical overspeed trips occurred at several plants (ANO, CPSES, STP, and WAT-3) during the preoperational-test phase. Licensee engineers had redesigned the supply-side condensate removal systems to assure the capability of the turbine-driven pumps to start following the initiation of a safety signal. The inspectors noted that condensate, which formed in the steam supply piping during a cold start, was an especially significant problem for units with long runs of piping between the steam admission valves and the turbine.

6.2 System Design

A variety of design approaches were used by licensees to control the condensate formation and removal. The inspectors found that half of the units (ANO-1; CPSES-1 and -2; DCPP-1 and -2; PVNGS-1, -2, and -3; and WAT-3) had long runs of piping between the steam isolation valve and the turbine (greater than 15.24 m [50 ft]). The steam isolation boundary for the remaining units was located close to the turbine. For example, the inspectors noted that:

- At ANO-1, the licensee included several steam traps to drain the steam lines during standby conditions. In addition, the licensee located the steam isolation valve at ANO-2 approximately 6.1 m [20 ft] from the turbine. After repeated overspeed trips, the licensee's engineers had revised the design to include an automatic warming valve in the steam line.

- At CPSES-1 and -2, the licensee initially addressed condensate formation and removal by adjusting the rate and timing of the condensate flow through the turbine. However, as a result of the recent mechanical overspeed trip, the licensee plans to upgrade their steam line drain system.

- At DCPP-1 and DCPP-2, the licensee ensured condensate removal by using three steam traps upstream of the steam line isolation valves and one steam trap between the steam line isolation valves and the trip-and-throttle valve.

- At PVNGS-1, -2, and -3, the licensee ensured condensate removal by using steam traps and drain lines upstream of the steam admission valves, between the steam admission valves and the trip-and-throttle valve, and between the trip-and throttle valve and the turbine. Additionally, the licensee reduced the effects of condensate formation by adjusting the rate and timing of the condensate flow through the turbine.

- At SONGS-2 and -3 and STP-1 and 2, the licensees used the steam admission valve as the trip-and-throttle valve (short distance to turbine). Drain lines were installed upstream of the trip-and-throttle valve at both facilities.

- At WAT-3, the licensee used heat tracing to minimize condensate formation by prewarming the steam supply piping.

- At WCNGS, the licensee kept the steam line warm by a small bypass line around the steam admission valve. This minimized the effects of moisture in the line.

6.3 <u>Steam Supply Valve Leakage</u>

The inspectors found that the steam supply valves at most units had leaked at least part of the time. The inspectors noted that most units had not established any upper bound for steam supply valve leakage. Only the engineers at PVNGS had established a quantifiable leakage rate (227 kg/hr [500 lbm/hr] or approximately 3.78 Lpm [1 gpm], total leakage from the four isolation valves), which specified when the valves should be repaired. When questioned, all licensee engineers contacted agreed that steam leakage significant enough to roll the turbine would be repaired. The inspectors noted that approximately 75 L [20 gallons] of condensate will fill the turbine and render it inoperable. Therefore, if the steam supply valve is leaking at 0.75 Lpm [0.2 gpm], then the turbine could fill up in less than 1 day if the steam traps and drains malfunction. The inspectors also noted that licensees typically had not established an upper limit on steam supply valve leakage as it related to steam trap and drain capacity. Therefore, the inspectors determined that it was important to have good operating status information about the readiness of the drain system.

6.4 Operating Status Information

The inspectors noted that the condensate removal system at several units had supply-side condensate high level alarms which would alert the operators to drain system failure. In fact, CPSES had recently reinstalled the supply-side condensate high level alarm, following the June 13, 1995, mechanical overspeed trip of the Unit 2 steam turbine-driven auxiliary feedwater pump.

The inspectors also found that seven units (ANO-1 and -2; DCPP-1 and -2; and, PVNGS-1, -2, and -3) did not have supply-side condensate high level alarms. Nevertheless, operating personnel at both ANO units routinely blew down the steam traps once per shift. In addition, DCPP-1 and -2 personnel checked the supply-side steam traps monthly by physically touching the lines to compare the temperatures. If the steam admission valves leaked, the DCPP-1 and -2 operators would blow down the turbine casing drains every 4 hours. Licensee personnel at PVNGS-1, -2, and -3 performed thermography once per week to verify that the steam traps were functioning correctly. Since minor steam supply valve leakage was allowed at these units, and since minor steam supply valve leakage can accumulate within 1 day to fill a turbine, the inspectors concluded that the operating practices at DCPP-1 and -2, and PVNGS-1, -2, and -3 were not optimal for detecting excessive condensate accumulation.

The recent mechanical overspeed trip at CPSES and the STP events highlight the importance of also maintaining exhaust-side traps and drains. The inspectors determined that only personnel from RBS and WNP-2 had installed alarms or high level indicators for the turbine or turbine exhaust-side steam traps or condensate pots/drains. Personnel from CPSES and CNS planned to add high level indicators for the turbine exhaust-side drains. (Reference Table 4, "Condensate Controls," attached, for site-specific information.)

6.5 Safety Classification

As stated above, condensate removal systems must function correctly to ensure the capability to automatically start and restart the standby turbines. However, the inspectors noted that most licensees have not formally recognized the safety function associated with condensate removal. The inspectors found that the licensees had upgraded the design classification of condensate removal components at the units that had experienced mechanical overspeed trips caused by inadequate condensate removal. For example, STP personnel established that the supply-side steam drains were safety related following discussions with the NRC Augmented Inspection Team (reference NRC Inspection Report 50-498/93-07; 50-499/93-07). Similarly, CPSES personnel were in the process of evaluating supply and exhaust drain systems to determine if they were safety related for condensate removal (reference NRC Inspection Report 50-445/95-13; 50-446/95-13).

Personnel at other facilities partially recognized a safety function associated with the condensate removal system. For example, the inspectors noted that the steam trap at WCNGS is considered safety related for only the pressure boundary capability; however, a level control valve in parallel with the steam trap is considered to be safety related for both the pressure boundary and condensate removal capability. At the remaining units, licensee personnel that recognized a safety function for the steam traps and/or drains had only formally recognized the pressure boundary function. (Reference Table 4, "Condensate Controls," attached, for site-specific information.)

The inspectors concluded that all of the licensees did not recognize that steam-line drains had a safety function to remove condensate until after discussions with NRC personnel. The inspectors were concerned that condensate removal was an important safety function because condensate accumulation upstream of the turbine governor valve will cause an overspeed trip to occur and prevent the standby pumps from performing their safety function.

6.6 Steam Trap and Drain Maintenance

The inspectors reviewed six auxiliary feedwater and one RCIC pump technical manuals. The inspectors noted that the licensees, for most of the units that used steam traps in the condensate removal system, had some type of preventive maintenance program for the steam traps. However, the inspectors noted that the licensees for two units (WAT-3; and WCNGS) had not established a preventive maintenance program for steam traps and drain pots. At the exit interview, personnel from WAT-3 stated that they planned to establish a preventive maintenance program for their steam traps. Personnel at WCNGS noted that they conditionally perform maintenance when the level alarm indicates that the steam trap is not functioning. In addition, none of the licensees had established a preventive maintenance program for the drains. The inspectors also noted that the licensees at four units had determined that inadequate preventive maintenance programs for their steam traps contributed to condensate induced mechanical overspeed trips (CPSES-1 and -2; and STP-1 and -2). Personnel at these sites redesigned their condensate removal system to eliminate the steam traps in the turbine drain system (Reference Table 4, "Condensate Controls," attached, for site-specific information.)

7 LUBRICATING AND HYDRAULIC OILS

7.1 Background

The inspectors historical review identified that use of the proper lubricating oil played a large role in the successful operation of safety-related steam turbine-driven standby pumps. Because oil provides the lubrication for moving parts, as well as the motive force for the governor valve, a failure in either could render the equipment inoperable. Various factors affect the performance of the oil. If the oil is too thick (viscous), the governor valve response could be sluggish. If the oil is aerated, lubrication of bearings could be lost and an erratic response of the governor valve could be experienced. If the oil chemically breaks down due to environmental factors (heat, humidity, and contaminants), the loss-of-speed control could occur.

7.2 System Designs

The inspectors reviewed the designs of the lubricating and hydraulic oil systems for 18 of the units surveyed. All of the units with EG-M/EG-R-type governors had a single oil sump that supplied oil for both lubrication and hydraulic controls. The units with PG-A-type governors had separate sumps for each function. In each of the units, the lubricating oil was distributed by way of slinger rings and the hydraulic control oil was distributed by way of a positive displacement pump.

The inspectors noted that the vendors (Dresser and Woodward) had provided the users of their equipment with guidelines for the type of oil to use for lubrication of moving parts and hydraulic control of the governor valve. In a letter, dated September 21, 1993, Dresser provided recommended viscosity requirements for oils at 37.8°C [100°F] and 98.9°C [210°F]. At 37.8°C, the viscosity range was 190 to 510 Saybolt Universal Seconds. At 98.9°C, the range was 43 to 65 Saybolt Universal Seconds. This generally corresponds to an International Standards Organization (ISO) Viscosity 32; however, oils with other ISO viscosity numbers fall within this range. For reliable governor actuator response during cold quick-starts (approximately 37°C [98°F]), Woodward stated that the maximum oil viscosity should be 300 Saybolt Universal Seconds.

The inspectors noted that all but two units used ISO Viscosity 32, or equivalent, oil for the turbine and governor applications. The two units, DCPP-1 and -2, used ISO Viscosity 68. The inspectors verified that the viscosity of this type oil was within the specifications provided by Dresser and Woodward.

7.3 Aeration

As previously mentioned, the inspectors noted that oil aeration had caused problems with both the lubrication and the hydraulic control of the turbine. Aeration will occur with excessive oil in the turbine bearings or during addition of oil to the governor. The loss of lubrication and possible bearing damage can result from aeration in the bearings; erratic speed control can result from aeration of the governor actuator. It was for these reasons that the vendor specified oil levels for the components. For example, the vendor required the oil level in the bearings to be at least 6.35 mm [0.25 in] above the bottom of the slinger ring, but no more than 1.5875 cm [0.627 in] above the bottom of the slinger ring. The inspectors noted that all but two of the units attempted to control the level within these guidelines. At WCNGS, the minimum and maximum levels were not annotated on the sight glass. At CNS the inspectors noted that the turbine oil level was approximately 6.35 mm [0.627 in] above the high level mark. The system engineer at CNS was not aware that a high oil level could be detrimental. After discussing the issue with Dresser, the licensee lowered the oil level to within the guidelines.

As stated in NRC Information Notice 94-84, "Air Entrainment in Terry Turbine Lubricating Oil System," dated December 2, 1994, the use of a 3.81 cm [1.5 in] oil return line from the bearings minimizes the effects of aeration in the bearing oil. However, the inspectors noted that two units (ANO-2 and WNP-2) had installed a 2.54 cm [1 in] line. In addition, ANO-2 personnel stated that they had observed the aeration phenomena after overfilling the oil system by 3.175 mm [0.125 in]. The licensee had tried unsuccessfully to vent the oil to improve drainage. During subsequent troubleshooting, ANO-2 found one internal orifice missing. As corrective action, ANO-2 personnel reset the pressure regulating valve and replaced the missing orifice. They now believe that they have resolved the oil aeration issue. The licensee for WNP-2 reported that they had not experienced any oil aeration problems.

The inspectors also noted that aeration of the oil for the governor actuator could occur during the addition of oil to the system. For this application, aeration could result in erratic operation of the governor actuator. The inspectors verified that procedures to remove the air prior to returning the system to an operable status were in place at all units. The inspectors did not consider any unit to be currently vulnerable to aeration caused by incorrect oil addition practices.

Several units had changed their turbine lubricating oil to address the problem of excessive solid formation due to vapor-phase inhibitors plating out at high standby temperatures. (Reference Table 5, "Lubricating and Hydraulic Oils," attached, for site-specific information.) The inspectors asked the licensees if they had performed any type of extended run to ensure that the change in lubricating oil did not inadvertently introduce new aeration problems. The inspectors noted that the original qualification at Dresser was 4 hours in length. The vendor stated that during initial turbine testing a 4-hour run was performed and used to detect aeration problems. If aeration occurred, the turbine oil system was modified prior to shipment. The inspectors noted that none of the licensees had performed a 4-hour run after an oil change out. Most turbines were run approximately 1 hour after the oil change. The inspectors noted that this testing was not comparable to the original qualification tests.

7.4 Oil Filtration

The inspectors noted that the location of the steam admission valves could also have a negative effect on the governor actuator response because the elevated temperature contributes to oil breakdown. Also, steam admission valve leaks can result in elevated temperatures and moisture. Contaminants can be controlled by such means as the use of filters when adding new oil, and the sampling of the oil on a periodic basis. The vendor recommended that oil be filtered through a 5μ filter prior to adding to the system. Licensee personnel at three units (CNS, RBS and WAT-3) were not filtering their oil prior to addition to the system. The inspectors found that the oil was sampled on a periodic basis at all units and no actual contaminated samples had been identified.

7.5 Oil Viscosity Requirements

As with any hydraulic control system, the viscosity of the oil affects the response of the system. As used in the safety-related steam turbine-driven standby pumps, the oil is usually more viscous when the component receives a start signal (because the temperature is cooler) than when operating. The thicker oil has trouble flowing through the small passages in the governor actuator, resulting in a sluggish response.

As stated above, the inspectors found that an oil with an ISO Viscosity 32 was used at all but two units (DCPP-1 and -2). At those units, an oil with an ISO Viscosity 68 was used. While the ISO Viscosity 68 would not function at as low a temperature as the ISO Viscosity 32, the environment at DCPP was such that the lower temperature capability was not a factor. However, the oil with the ISO Viscosity 68 was capable of operating at a higher temperature, which was an added benefit. The inspectors concluded that licensee personnel had specified appropriate oil viscosity limits

7.6 Maintenance Practices

Maintenance practices related to oil included sampling, replacement, and filtration prior to addition. In a September 21, 1993, letter to the licensees, Dresser recommended a maintenance program to sample the oil at intervals of 30 days and renewal of all additives at 6-month intervals. The inspectors found that an oil sampling program to evaluate the condition of the oil in the standby steam turbine-driven pump systems was in place at all of the units. Licensee personnel sampled the oil periodically (usually annually) and no oil had been replaced as the result of unacceptable oil test results.

TABLE 1 - TURBINE SURVEILLANCE REQUIREMENTS	
TURBINE SURVEILLANCE AND POST MODIFICATION TESTING REQUIREMENTS	COLD QUICK START TEST REQUIRED BY PROCEDURE (INFORMATION NOTICES 88-09 and 93-51)
ANO-1	INITIAL TURBINE TEMPERATURE IS RECORDED
ANO-2	INITIAL TURBINE TEMPERATURE IS RECORDED
CNS	NO
CPSES-1,-2	QUARTERLY
DCPP-1,-2	QUARTERLY
PVNGS-1,-2,-3	YES
RBS	RECCMMENDED QUARTERLY
SONGS-2,-3	YES
STP-1,-2	YES
WNP-2	ANNUALLY
WAT-3	NO
WCNGS	YES

TABLE 2 - TURBINE DESIGN VERIFICATION TESTS								
TURBINE DESIGN PREOPERATIONAL TESTS	4 HOUR STAND ALONE OPERATION WITH NO AC	LOSS OF ALL AC TO TURBINE	LOWEST STEAM INLET PRESSURE (COUPLED)	HIGH STEAM INLET PRESSURE	FULL FLOW TEST AT NORMAL OPERATING TEMP AND PRESSURE	NUMBER OF CONSECUTIVE STANDBY STARTS	RESTART	ENDURANCE RUN
ANO-1	NO	NO	NO	YES	YES	NONE	NO	NO
ANO-2	NO	NO	NO	YES	YES	NONE	NO	NO
CNS	NO	NO	YES	YES	YES	SEVERAL STARTS	NO	NO
CPSES-1, -2	NO	NO	NO	YES	YES	5	YES	48 HOURS
DCPP-1, -2	NO	NO	YES	YES	YES	2	NO	48 HOURS
PVNGS-1, -2, -3	YES	YES	YES	YES	YES	5	YES	72 HOURS
RBS	NO	YES	YES	YES	YES	2	NO	2 HOURS
SONGS-2, -3	NO	NO	NO	YES	YES	NONE	YES	24 HOURS
STP-1, -2	NO	YES	NO	YES	YES	NONE	NO	48 HOURS
WNP-2	NO	NO	YES	YES	YES	5	NO	NO
WAT-3	NO	YES	YES	YES	YES	5	NO	YES
WCNGS	NO	NO	NO	YES	YES	5	YES	24 HOURS

TABLE 3 - GOVERNOR SYSTEMS

	STEM MATERIAL (INFORMATION NOTICE 94-66 and SUPPLEMENT 1)	PLANNED STEM MATERIAL CHANGE (INFORMATION NOTICE 94-66 and SUPPLEMENT 1)	GOVERNOR VENDOR PREVENTIVE MAINTENANCE ACTIVITIES	PGA/PG-PL SHUTDOWN ASSEMBLY INSTALLED (INFORMATION NOTICE 86-14 and SUPPLEMENT 2)	GOVERNOR/STEM TESTS (INFORMATION NOTICE 94-66 and SUPPLEMENT 1)
ANO-1	410 STAINLESS STEEL (SS) WITH NICKEL CHROME STEM TREATMENT	FERRALIUM	REFURBISH EVERY THIRD OUTAGE	N/A	QUARTERLY SPEED TRACES
ANO-2	FERRALIUM	N/A	REFURBISH EVERY THIRD OUTAGE	N/A	MONTHLY, SOON TO BE QUARTERLY SPEED TRACES
CNS	410 SS WITH GAS NITRIDED STEM TREATMENT	INSPECT INSTALLED STEM IN NOVEMBER LIQUID NITRIDED STEM IN STORES	**NONE**	N/A	**STOPPED WEEKLY MANUAL STROKE TESTS IN MAY 1995**
CPSES-1, -2	INCONEL	N/A	REFURBISH EVERY FIVE YEARS	YES	MONTHLY VALVE POSITION INDICATION, STRAIN GAGE, DISCHARGE PRESSURE, VISUAL
DCPP-1, -2	410 SS WITH GAS NITRIDED STEM TREATMENT	N/A	**NONE**	NO, ADMINISTRATIVELY CONTROLLED	MONTHLY FLOW TRACES
PVNGS-1, -2, -3	**410 SS WITH UNKNOWN TYPE OF STEM TREATMENT, PROBABLY LIQUID-NITRIDED**	INCONEL 718	REPLACE EVERY FIVE YEARS	N/A	QUARTERLY SPEED TRACES & MONTHLY MANUAL STROKE
RBS	422 SS WITH ALUMINUM NICKEL STEM TREATMENT	N/A	REPLACE EVERY THIRD OUTAGE	N/A	**BIWEEKLY STROKE & BREAKAWAY TORQUE**
SONGS-2, -3	410 SS WITH NICKEL ALUMINIZING STEM TREATMENT	N/A	REPLACE EVERY 10 YEARS	N/A	SPEED TRACES AT DISCRETION OF SYSTEM ENGINEER
STP-1, -2	INCONEL	N/A	REFURBISH EVERY FIVE YEARS	YES	MONTHLY SPEED TRACES
WNP-2	**410 SS WITH UNKNOWN TYPE OF STEM TREATMENT**	**INSPECTION PLANNED DURING NEXT OUTAGE**	**NONE**	N/A	QUARTERLY SPEED TRACES & MANUAL VALVE STROKE
WAT-3	FERRALIUM	N/A	REPLACED MAY 1994	N/A	**WEEKLY 0.125" MANUAL STROKE**
WCNGS	410 SS WITH GAS NITRIDED STEM TREATMENT	**410 SS WITH LIQUID NITRIDED STEM TREATMENT IN STORES**	**NONE**	N/A	SEMIANNUAL SPEED TRACES

TABLE 4 - CONDENSATE CONTROLS

	STEAM SUPPLY INDICATION FOR CONDENSATE REMOVAL (INFORMATION NOTICES 86-14 and 93-51)	EXHAUST SIDE INDICATION FOR CONDENSATE REMOVAL (INFORMATION NOTICE 93-51)	LICENSEE MAINTAINS STEAM SUPPLY VALVE LEAKAGE CRITERIA WHICH IS LESS THAN TURBINE ROLL (INFORMATION NOTICE 86-14)	OPERATOR MONITORING (INFORMATION NOTICES 86-14 and 93-51)	STEAM TRAP PREVENTIVE MAINTENANCE (INFORMATION NOTICES 86-14 and 93-51)	CONDENSATE REMOVAL SAFETY FUNCTION RECOGNIZED
ANO-1	NO	NO	ENGINEERING JUDGEMENT	DRAIN ONCE PER SHIFT	YES	PARTIALLY SAFETY-RELATED/ PRESSURE BOUNDARY ONLY
ANO-2	NO	NO	ENGINEERING JUDGEMENT	DRAIN ONCE PER SHIFT	YES	PARTIALLY SAFETY- RELATED/ PRESSURE BOUNDARY ONLY
CNS	YES	PLANNED	NOT DETERMINED	MONITOR UPSTREAM LEVEL ALARM	ONCE PER REFUELING CYCLE	NONSAFETY-RELATED
CPSES-1, -2	YES	PLANNED	NOT DETERMINED	MONITOR UPSTREAM LEVEL ALARM	YES	SAFETY-RELATED LEVEL INSTRUMENTATION
DCPP-1, -2	NO	NO	NOT SPECIFIC	MONTHLY TRAP TESTING	YES, QUARTERLY SONIC TESTS	SAFETY-RELATED
PVNGS-1, -2, -3	NO	NO	500 LBM/HR (~1 GPM) TOTAL LEAKAGE FROM ALL FOUR STEAM ADMISSION VALVES	DRAIN ONCE PER SHIFT QUARTERLY THERMOGRAPHY	YES	SAFETY-RELATED DRAIN
RBS	YES	YES	NOT SPECIFIC	LEVEL ALARMS, QUARTERLY LEVEL INDICATION VERIFICATION	YES	LEVEL INDICATION SAFETY RELATED
SONGS-2, -3	YES	NO	NOT SPECIFIC	CHECK LEVEL AND/OR TEMPERATURE ONCE PER SHIFT	N/A	PARTIALLY SAFETY-RELATED / PRESSURE BOUNDARY ONLY
STP-1, -2	YES	NO	NOT DETERMINED	N/A	N/A	NONSAFETY-RELATED
WNP-2	YES	YES	NOT DETERMINED	LEVEL ALARMS	YES	NONSAFETY-RELATED
WAT-3	YES	NO	NOT DETERMINED	DRAIN ONCE PER SHIFT	YES	NONSAFETY-RELATED
WCNGS	YES	NO	NOT SPECIFIC	LEVEL ALARM	CONDITIONAL PM	SAFETY-RELATED LEVEL CONTROL VALVE FOR CONDENSATE REMOVAL

TABLE 5 - LUBRICATING AND HYDRAULIC OILS									
	TURBINE / GOVERNOR OIL	STANDBY TEMPERATURE > 120°F	CHANGED OIL TYPE	4 HOUR RUN AFTER OIL CHANGE	5u FILTER (INFORMATION NOTICE 86-14, SUPPLEMENT 2)	GOVERNOR OIL SUMP INSPECTION (INFORMATION NOTICE 86-14, SUPPLEMENT 2)	GOVERNOR OIL SYSTEM FLUSH AND CLEAN (INFORMATION NOTICE 86-14, SUPPLEMENT 2)	CHANGE TURBINE OIL AND FILTER (INFORMATION NOTICE 86-14, SUPPLEMENT 2)	OIL LEVEL INDICATION
ANO-1	CHEVRON GST-32	YES	YES	NO	YES	YES	YES	YES	SAT
ANO-2	CHEVRON GST-32	YES	YES	NO	YES	YES	YES	YES	SAT
CNS	**VAPROTEC LIGHT**	NO	YES	N/A	**NO**	NO	NO	YES	SAT
CPSES-1, -2	MOBIL DTE-797	NO	YES	NO	YES	YES	YES	YES	SAT
DCPP-1, -2	**SHELL VSI-68** / GST-68	NO	YES	NO	YES	YES	YES	YES	SAT
PVNGS-1, -2, -3	**SHELL VSI-32**	NO	NO	N/A	YES	YES	YES	YES	SAT
RBS	**VAPROTEC LIGHT**	NO	EVALUATING FOR CHANGE DURING NEXT REFUELING OUTAGE	N/A	**NO**	NO, BUT SAMPLED GOVERNOR OIL	NO	YES	SAT
SONGS-2, -3	**VAPROTEC LIGHT**	YES	NO	N/A	YES	YES	YES	YES	SAT
STP-1, -2	MOBIL RAD-797	YES	YES	NO	YES	YES	YES	YES	SAT
WNP-2	MOBIL DTE-797	NO	YES	NO	YES	NO	NO	YES	SAT
WAT-3	MOBIL DTE-797	YES	YES	NO	**NO**	REPLACED EGR	YES	YES	SAT
WCNGS	MOBIL RAD-797	YES	YES	NO	YES	YES	YES	YES	**UNSAT**

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Arizona Public Service Company

K. Chavet, Industry Operating Events Coordinator
*B. Eklund, Consultant, Compliance Group
A. Fernandez, Mechanical Maintenance Engineer
N. Hallas, Materials Engineer
C. Landstrom, System Engineer
C. Lewis, Senior Engineer, Instrumentation and Controls

1.2 Dresser-Rand

C. Slater, Service Engineer

1.3 Entergy Operations, Inc.

1.3.1 Arkansas Nuclear One, Units 1 and 2

*T. Mitchell, Unit 2 System Engineering Manager
*T. Morse, System Engineer, Unit 1
*D. Nilius, System Engineer, Unit 2
*B. Short, Licensing Engineer
*M. Smith, Licensing Supervisor
*A. Wrape, Unit 1 System Engineering Manager

1.3.2 River Bend Station

*D. Gilley, System Engineering Supervisor
J. Maher, Licensing Engineer
*E. Roan, Acting System Engineering Supervisor
*W. Stuart, System Engineer
*J. Summers, Licensing Specialist
*R. West, System Engineering Manager
*G. Zinke, Quality Assurance Manager

1.3.3 Waterford Steam Electric Generating Station, Unit 3

*R. Burski, Director Nuclear Safety
*P. Gropp, Mechanical Design Engineering Supervisor
*T. Gaudet, Operations Licensing Supervisor
*J. Hologa, Manager of Mechanical and Civil Design Engineering
*R. O'Quinn, Mechanical System Engineer
R. Quinnold, System Engineer
*D. Shipman, Plant and Scheduling Manager
*D. Urciuoli, Senior Licensing Engineer
*D. Vinci, Licensing Manager
*M. Waldschmidt, System Engineer

1.4 Houston Lighting and Power Company

*R. Asbury, Auxiliary Feedwater System Engineer
*M. Chambers, Acting Power Production System Engineering Supervisor
*D. Schulker, Compliance Engineer
*M. Kanavos, Manager Mechanical Fluids Division

1.5 Nebraska Public Power District

*M. Bennet, Nuclear Licensing and Safety Supervisor
*J. Gausman, Plant Engineering Manager
T. Gauthier, System Engineer
*P. Graham, Senior Engineering Manager
*R. Jones, Senior Manager Safety Assessment
*O. Olson, Core Cooling Supervisor
B. Victor, Licensing Engineer

1.6 Pacific Gas and Electric Company

*J. Bard, Senior Engineer, Condensate and Feed
W. Barkhuff, Piping Engineer
*M. Coward, System Engineer
C. Harbor, NRC Interface
*P. Milne, System Engineer
*L. Parker, Independent Safety Engineer

1.7 Southern California Edison Company

*P. Blakeslee, Supervisor, Heat Removal
*C. Diamond, System Design Engineer
J. Hirsch, Manager, Power Generation
*B. Kaplan, Compliance Engineer
*J. Marr, Cognizant Engineer
*G. Plumlee, Compliance Supervisor
L. Pressey, Business Administration Supervisor, Maintenance

1.8 Texas Utilities Electric Company

*R. Flores, System Engineering Manager
*T. Hope, Licensing Supervisor
*B. Reppa, System Engineer
A. Saunders, Nuclear Steam Supply System Engineering Supervisor

1.9 Washington Public Power Supply System

*L. Fernandez, Licensing Engineer
*D. Giroux, Previous System Engineer
*T. Hancock, System Engineer
*B. Pensek, Previous System Engineer

1.10 Wolf Creek Nuclear Operating Corporation

*M. Ferrel, System Engineer
B. Grieves, Supervisor, Auxiliary Systems
*S. Hatch, Engineering Specialist
*W. Norton, Manager, System Engineering
*L. Ratzlaff, Engineering Supervisor
C. Reekie, Compliance Specialist III
*J. Yunk, Engineering Specialist
*S. Yunk, System Engineer

1.11 NRC

*W. Smith, Senior Resident Inspector

The personnel listed above, which are marked with an asterisk, attended the exit interview by telephone.

2 EXIT MEETING

An exit meeting was conducted by telephone on November 9, 1995, with personnel from each facility. During this meeting, the inspectors reviewed the scope and findings of this report. Licensee personnel expressed positions on the inspection findings which have been documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

LIST OF ACRONYMS

AFW	Auxiliary Feedwater System
ANO	Arkansas Nuclear One
CFR	Code of Federal Regulations
CNS	Cooper Nuclear Station
CPSES	Comanche Peak Steam Electric Station
DCPP	Diablo Canyon Power Plant
EFW	Emergency Feedwater System
NRC	Nuclear Regulatory Commission
PVNGS	Palo Verde Nuclear Generating Station
RBS	River Bend Station
RCIC	Reactor Core Isolation Cooling System
SONGS	San Onofre Nuclear Generating Station
STP	South Texas Project
WAT-3	Waterford Steam Electric Generating Station, Unit 3
WCNGS	Wolf Creek Nuclear Generating Station
WNP-2	Washington Nuclear Project-2